FINAL REPORT

POTENTIAL FOR COGENERATION AND GENERATION FROM WASTE IN ALBERTA

Prepared for

The Honourable Rick Orman
Minister of Energy
Government of Alberta
Edmonton, Alberta

Prepared by

Applied Decision Analysis and Synergic Resources Corporation

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for the Alberta Department of Energy

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The preparation of this report involved COGENMASTER computer runs too numerous to include in the report. If there are any questions concerning these COGENMASTER runs, or other questions and comments about the report, they should be directed to

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1.0 Overview

This report analyzes the potential for cogeneration and generation from waste in Alberta. Cogeneration is defined as the joint production from the same input fuel of significant quantities of electricity and thermal energy for use in space heating or cooling, or industrial or commercial processes. The analysis of cogeneration was performed from February 1991 through March 1992 by Applied Decision Analysis and Synergic Resources Corporation (SRC) under Terms of Reference and direction from the Alberta Department of Energy.

The study presents both technical and economic potential under a number of scenarios for fuel, electricity, and capital costs. Potential refers to the long run implementation of these generation resources under a fixed scenario. The potential calculations do not consider present installed capacity or changes in scenarios into the future.

The study also tries to present the results of the scenarios in such a way that users of this report can extrapolate to the user's own scenarios. The study does not predict future implementation of cogeneration and generation from waste in Alberta. Such a prediction would have required estimates of the probabilities of the different scenarios and of the short run penetration of technologies. Such estimates were beyond the Terms of Reference for this study.

The analysis is based on individual industrial and commercial segments. Segments were included in the analysis based on their significance as a potential source of electricity supply and were differentiated so as to obtain homogeneity in thermal and economic conditions within each segment. The segments analyzed are shown in Table 1-1.

Segment
Oilsands Mining
Oilsands In-situ
Oil Refineries & Upgraders
Turboexpanders
Kraft Pulp Mills
Petrochemical Plants
Large Educ. Institutions
Hospitals
Food Industry
Sweet Gasplants
Sour Gasplants
Gas Flares
Municipal Solid Waste (MSW)
Saw, Panelboard, CTMP Mills

Table 1-1. Segments analyzed in this report

Additional segments considered for analysis but not included in the final paper are tabulated in Table 1-2. These segments were not analyzed because they failed to show opportunities for cogeneration in the initial screening.

Cement
Coal
Metals
Mining
Other industrial
Other commercial

Table 1-2. Segments removed from the analysis

Based on the study's Terms of Reference from the Alberta Department of Energy, facilities with under 2MW of generation potential were generally excluded from the study. The results of this report are based on extensive data collection on the identified segments, both in Alberta and in other markets, careful modeling of the

economic and thermal characteristics of typical firms in each segment, and insight from extensive interviews with experts from the industries modeled and other stakeholder groups. The report is organized into five sections, Summary of Results, Potential for Generation, Sensitivity to Risk and Other Factors, Stakeholder Viewpoints, and Policy Implications and Conclusions. Each of these sections is described below.

Summary of Results

The Summary of Results aggregates the results of the detailed segment by segment analyses and provides a concise view of the potential for cogeneration and generation from waste in Alberta.

Potential For Generation

The section on Potential for Generation begins with an explanation of the assumptions underlying the technical analyses of each segment. The assumptions subsection is followed by a segment by segment analysis including a qualitative description, a technical analysis, and an analysis of economic potential for each segment.

The technical analyses are based on COGENMASTER, a state-of-the-art PC model of cogeneration economics developed by SRC for EPRI and used widely by utilities and government agencies in the United States and other countries. (COGENMASTER is described in detail in Appendix E.) These analyses proceed in a "bottom-up" fashion, as COGENMASTER is used to determine the economics of cogeneration for a "representative facility" in each segment and this analysis is extrapolated to the segment as a whole.

Peak thermal and electric loads are used to determine the technical potential of a representative facility. Total segment size is defined as the total capacity of all facilities that consume or have the potential to produce more than 2 MW of electricity. The number of representative facilities in a segment is determined by dividing the total segment size by the capacity of the representative facility. Technical potential for a

segment is determined by multiplying the technical potential of a representative facility by the number of representative facilities in the segment.

The output of COGENMASTER is a payback period or internal rate of return (IRR) measure for a representative facility. Through an acceptance distribution, payback can be used to determine the percent of decision makers that install cogeneration or generation from waste. An acceptance distribution shows the percent of decision makers that, at a particular payback, will find it economically desirable to implement an energy-efficiency investment. Acceptance distributions capture the long-run impact of many independent decision-makers applying different investment criteria.[1]

Acceptance rates and estimates of total segment size are used to scale economic cogeneration potential for a representative facility up to the economic potential for the segment. For example, assume the typical plant has the technical potential for 5 MW of cogeneration, segment size is equivalent to the size of 3.5 typical plants, and the payback indicates a 30% acceptance of cogeneration. The estimated economic potential will be 5 x 3.5 x 0.3 equals 5.25 MW.

The analysis incorporates various "scenarios" involving different levels of gas, electric use, and electric buyback rates, cogeneration capital costs, and waste tipping fees to indicate sensitivities to these variables and to maintain the applicability of the analysis over time.

Sensitivity to Risk and Other Factors

The section on Sensitivity to Risk and Other Factors consists of three subsections. The first subsection considers the sensitivity of the forecasts to the uncertainties identified by stakeholders. The second subsection considers sensitivity to some of the same uncertainties from the perspective of the individual cogeneration

[1]Because a payback criterion is used, a user can examine the impacts of capital cost variations very easily. For example, to determine the potential in a sector with a 25% reduction in capital costs, the user would make a corresponding 25% reduction in payback periods and use the graphs presented to determine the altered level of potential.

investment decision maker. The final subsection examines the phenomenon of penetration of cogeneration technologies.

Stakeholder Viewpoints

The section entitled Stakeholder Viewpoints summarizes the insights gained from meetings with diverse stakeholders about the future of cogeneration and generation from waste in Alberta.

Policy Implications and Conclusions

The section on Policy Implications examines all the results presented previously from the policy perspective. It considers implications of both utility policy and government policy on the cogeneration decision.

2.0 Summary of Results

This section presents a summary of the technical and economic potential for cogeneration and generation from waste in Alberta. A number of different industrial, commercial, and waste generation segments are considered. Details on each segment are presented in Section 3 of this report. The segments included in this summary, their assumed 1992 size, and their assumed compound annual growth rate through 2005 are shown in Table 2-1.

Segment	1992 Size	CAGR
Oil sands mining	225,000 bbl/day	5%(1)
Oil sands in-situ	116,000 bbl/day	8%(1)
Oil refineries & upgraders	394,910 bbl/day	2%(1)
Turboexpanders	58 sites	3%(2)
Kraft pulp mills	1.5 M a.d.t./year	2.6%(1)
Petrochemical plants	19 plants	7.5%(1)
Large educational institutions	10 institutions	1%(3)
Hospitals	13 hospitals	2.4%(2)
Food industry	14 plants	2.5%(4)
Sweet gas plants	12 plants	3%(1)
Sour gas plants	16 plants	3%(1)
Gas flares	127 flares	0%(5)
MSW	3,600 tonne/day	1%(3),(6)
Saw, panelboard, CTMP mills	1.5 M ODtonnes/day	1%(7)

(1) Based on ERCB production projections

(2) Based on ERCB energy consumption projections (CO2 Report)

(3) Based on population projections (UN Population Division)

(4) Based on ERCB GDP growth projections

(5) Based on ERCB Gas Department projections

(6) Assumes all waste from Edmonton and Calgary and 50% of waste from other large cities

(7) Based on Alberta Wood Residue Inventory projections

Table 2-1. Size and growth of segments

Two alternative scenarios are considered in this summary in order to capture the difference in cogeneration and generation from waste potential between 1992 and 2005. The 1992 scenario is based on actual 1992 segment sizes and rates. The 2005 scenario is based on predicted segment sizes and rates. The rate levels assumed are tabulated in Table 2-2, below.

	1992	2005
Gas Price	\$0.05/m (\$1.32/GJ)	\$0.10/m (\$2.64/GJ)
Retail Electric Rate:		
Large Industrial	3.0¢/kWh	3.0¢/kWh
Commercial	5.25¢/kWh	5.25¢/kWh
Buyback Rate:		
Generation from Waste	3.0¢/kWh	3.0¢/kWh
Cogeneration	equal to retail rate	equal to retail rate
Wood Cost	\$0/ODtonne	\$0/ODtonne
MSW Tipping Fee	\$35/tonne	\$35/tonne
*NOTE: All rates are in real 1992 dollars		

Table 2-2. Base case rate scenarios for 1992 and 2005

Though the base case retail electric rate is set at 3 cents per kWh for industrial segments and 5.25 cents per kWh for commercial segments in both scenarios, results are presented for various electricity price levels within each scenario. The sensitivities to electric rate are performed assuming a constant differential of 2.25 cents per kWh between industrial and commercial retail rates, a waste generation buyback rate equal to the industrial retail rate, and a cogeneration buyback rate for any given segment equal to the retail rate for that segment.

The results of this analysis show the impact of two opposing trends on the development of cogeneration and generation from waste in Alberta. A number of the segments analyzed in this report are predicted to grow very rapidly (as shown in Table 2-1). Thus, opportunities for cogeneration and hence technical potential are expected to increase over the time horizon investigated. Concurrently, however, gas rates are predicted to grow faster than electric rates (as shown in Table 2-2). Since gas is the primary fuel for most cogeneration applications, the economics of cogeneration are predicted to become less attractive by 2005.

Technical Potential

The level of total technical potential for cogeneration and generation from waste is extremely dependent on whether the electric production capabilities of the cogeneration systems are sized to provide peak electric loads or are sized to take advantage of the peak thermal load. The logic of sizing to peak electric or peak thermal loads is explained in Section 3. Figure 2-1 presents the share of 1992 technical potential represented by each investigated segment assuming cogeneration systems are sized to peak electric load. Total technical potential in this case is approximately 1893 MW. Figure 2-2 presents the breakdown of 1992 technical potential assuming cogeneration systems are sized to peak thermal load. Technical potential is much greater, 4119 MW, in this case.

Predicted growth in the investigated segments results in significantly higher technical potential in 2005. The share of 2005 technical potential represented by each segment assuming cogeneration systems are sized to peak electric load is shown in Figure 2-3. Total technical potential in 2005 is approximately 3412 MW in this case. Figure 2-4 illustrates the share of technical potential for each segment assuming the electric production of cogeneration systems are sized to take advantage of the peak thermal load. Technical potential is 7786 MW in 2005 in this case.

The Petrochemicals, Kraft pulp mills, and Oil sands mining segments contribute a larger fraction of the total technical potential if systems are sized to thermal load due to their relatively large ratio of thermal to electric requirements. The Petrochemical and In-situ oil sands segments exhibit marked growth in their fractional contribution to total technical potential between 1992 and 2005. In both years and under both sizing assumptions, the three largest segments contribute over half the total technical potential.

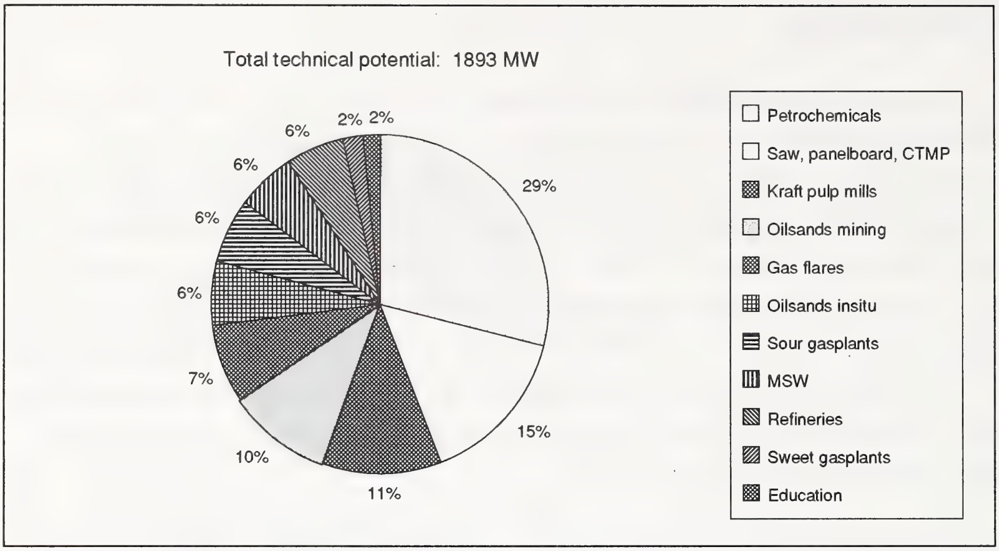

Figure 2-1. Base case 1992 technical potential - peak electric sizing

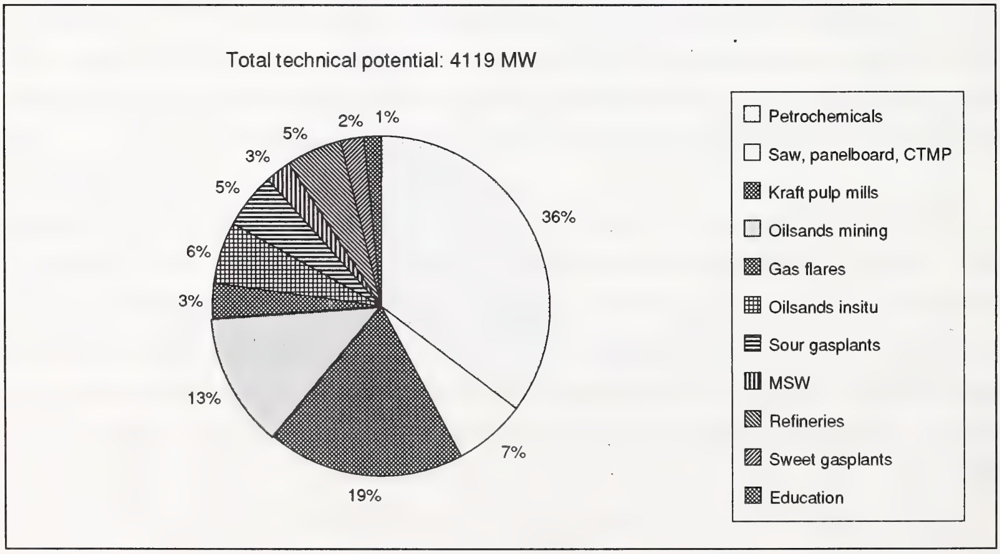

Figure 2-2. Base case 1992 technical potential - peak thermal sizing

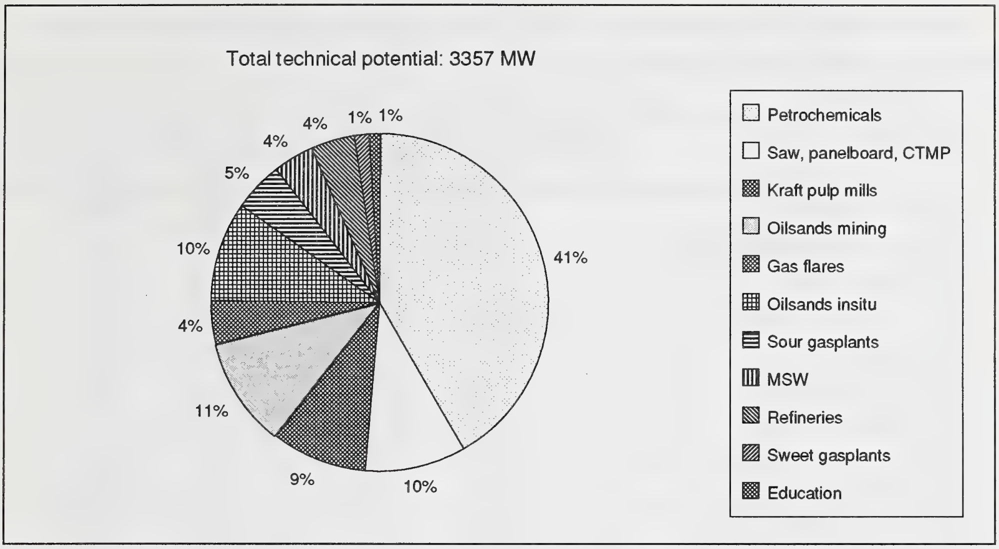

Figure 2-3. Base case 2005 technical potential - peak electric sizing

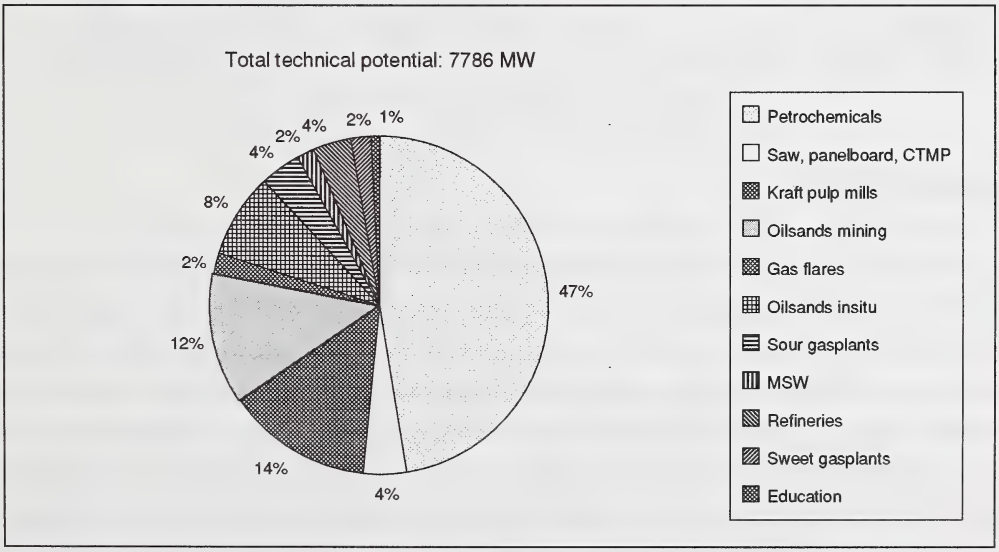

Figure 2-4. Base case 2005 technical potential - peak thermal sizing

Technical potential for the 1992 and 2005 scenarios is summarized for each segment and for both sizing assumptions in Table 2-3 below.

Segment	Size to Peak Electric		Size to Peak Thermal	
	1992	2005	1992	2005
Petrochemicals	530	1366	1393	3593
Saw, panelboard, CTMP	280	320	280	320
Kraft pulp mills	210	294	749	1048
Oil sands mining	182	345	497	940
Gas flares	135	135	135	135
Oil sands in-situ	116	316	230	627
Sour gas plants	107	154	202	290
MSW	104	120	104	120
Refineries	104	136	206	269
Sweet gas plants	32	49	94	140
Education	29	31	57	63
Hospitals	17	24	86	119
Turboexpanders	17	26	17	26
Food industry	31	42	71	96
TOTAL	1893	3357	4119	7786

All numbers are rounded to the nearest MW. The rounded total may differ slightly from the sum of rounded segment contributions.

Table 2-3. Technical potential (MW)

Economic Potential

Of the technical potential identified in 1992, only a minute fraction is economic at current rates. Figure 2-5 depicts economic potential in 1992 as a function of electric rates. Figure 2-5 shows total economic potential, not net potential in addition to present installations; and Figure 2-5 assumes that no cogeneration or generation from waste is currently in place. The electric rate shown is the large industrial rate -- the rate applied to commercial segments (hospitals and education) is 2.25¢/kWh above the rate shown. Thus, the economic potential number shown for an industrial rate of 3¢/kWh assumes that industrial segments pay 3¢/kWh but that commercial segments pay 5.25¢/kWh. Generation from waste segments are assumed to receive a buyback rate equal to the industrial retail rate. The choice of sizing strategy for cogeneration systems has a large impact on economic potential. A separate line is shown for each of the two sizing assumptions.

In the case where cogeneration facilities size to peak thermal load, they will potentially be selling a large amount of electricity back to the utility. In this case, the numbers along the X-axis in Figure 2-5 and similar figures throughout this report should be interpreted as an industrial buyback rate rather than an industrial retail rate. For simplicity, the discussion that follows will assume the two rates are equal.[2]

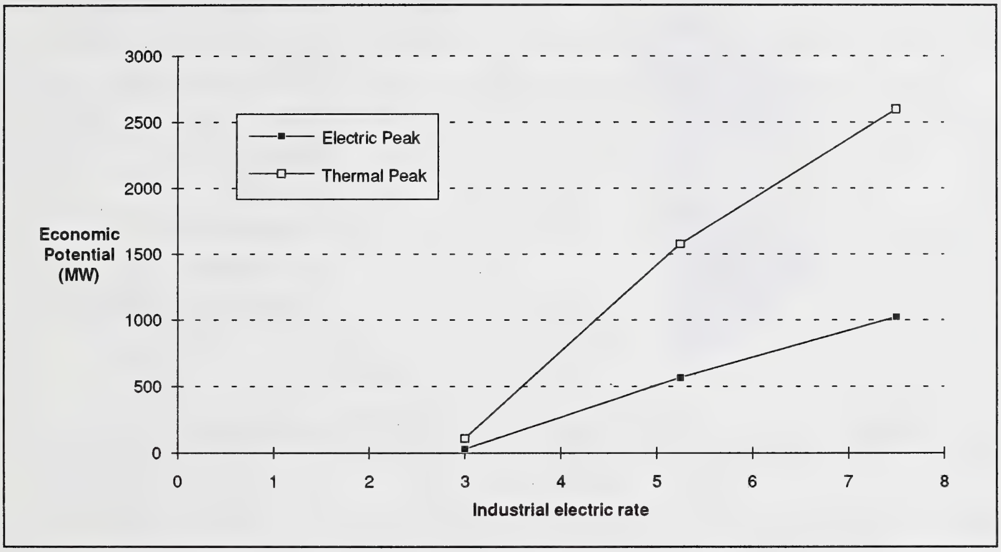

Figure 2-5. Economic potential in 1992

In the 1992 scenario of low gas prices and at current electric rates (3¢/kWh industrial, 5.25¢/kWh commercial), economic potential is approximately 28 MW if all cogeneration systems are sized to peak electric load and approximately 109 MW if all cogeneration systems are sized to peak thermal load. Note that potential increases greatly with real increases in electric rates. At an industrial retail rate of 5.25¢/kWh , economic potential is approximately 566 MW assuming peak electric sizing and approximately 1577 MW assuming peak thermal sizing, while at a 7.5¢/kWh industrial rate potential is approximately 1021 MW assuming peak electric sizing and 2598 MW assuming peak thermal sizing.

A breakdown of economic potential at current electric rates into segments is given in Figures 2-6 and 2-7 for the 1992 scenario. Figure 2-6 shows the breakdown of the total 28 MW of economic potential assuming cogeneration systems are sized to

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[2]No environmental adders or subsidies are provided for resource efficiency.

peak electric load. Figure 2-7 shows the breakdown of the total 109 MW assuming cogeneration systems are sized to peak thermal load.

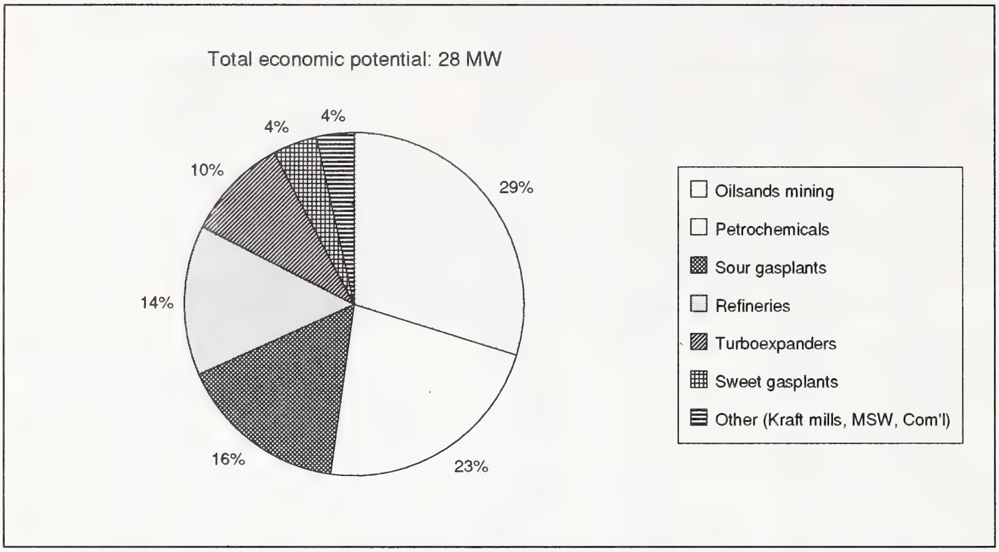

Figure 2-6. Base case 1992 economic potential - electric peak

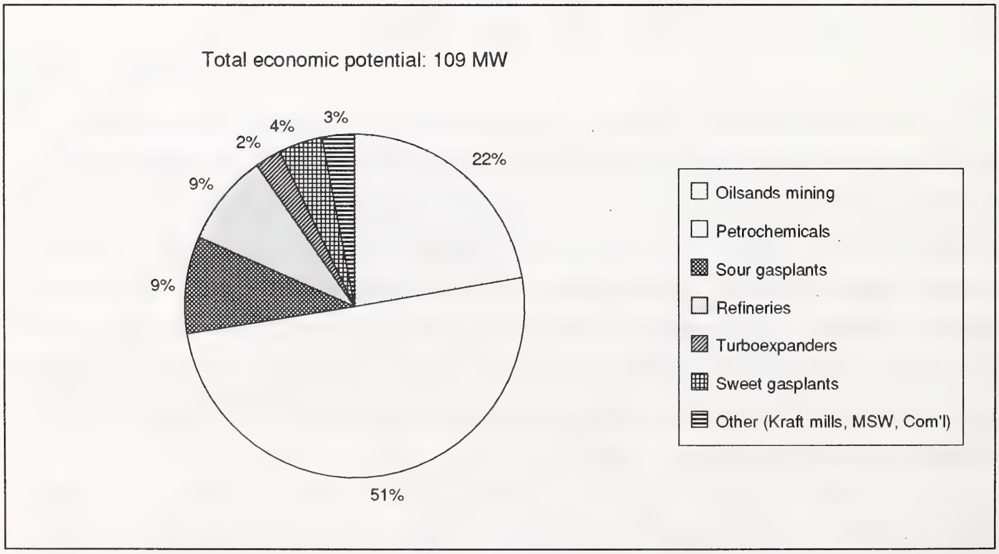

Figure 2-7. Base case 1992 economic potential - thermal peak

The Petrochemical segment's share of total economic potential is over twice as large under the assumption of peak thermal sizing as it is under that of peak electric sizing. This is due to relatively good economics and a relatively high ratio of thermal to electric load in this segment.

In 2005, economic potential is significantly greater than in 1992 for high electric rates, but is slightly lower at the predicted industrial electric rate of 3¢/kWh. Figure 2-8 illustrates economic potential as a function of electric rates for the 2005 scenario. Again, potential is highly dependent on whether cogeneration systems are sized to peak thermal or peak electric load.

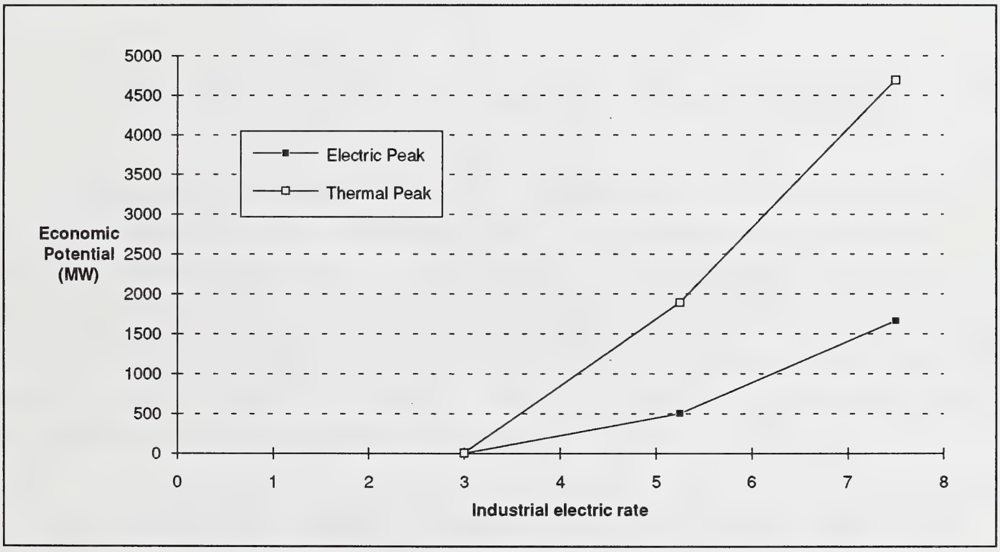

Figure 2-8. Economic potential in 2005

In 2005, economic potential is low at predicted electric rates despite increased technical potential because of the overriding effect of higher real gas prices. At predicted rates (3¢/kWh industrial), economic potential is approximately 12 MW if all cogeneration systems are sized to peak electric load and approximately 54 MW if all cogeneration systems are sized to peak thermal load. Again, potential increases greatly with real increases in electric rates. At 5.25¢/kWh (industrial rate), economic potential is approximately 499 MW assuming peak electric sizing and approximately

1891 MW assuming peak thermal sizing, while at 7.5¢/kWh potential is approximately 1659 MW assuming peak electric sizing and 4691 MW assuming peak thermal sizing.

A breakdown of economic potential at predicted electric rates into segments is given in Figures 2-9 and 2-10. Figure 2-9 shows the breakdown of the 2 MW of total economic potential assuming cogeneration systems are sized to peak electric load. Figure 2-10 shows the breakdown of the 4 MW assuming cogeneration systems are sized to peak thermal load.

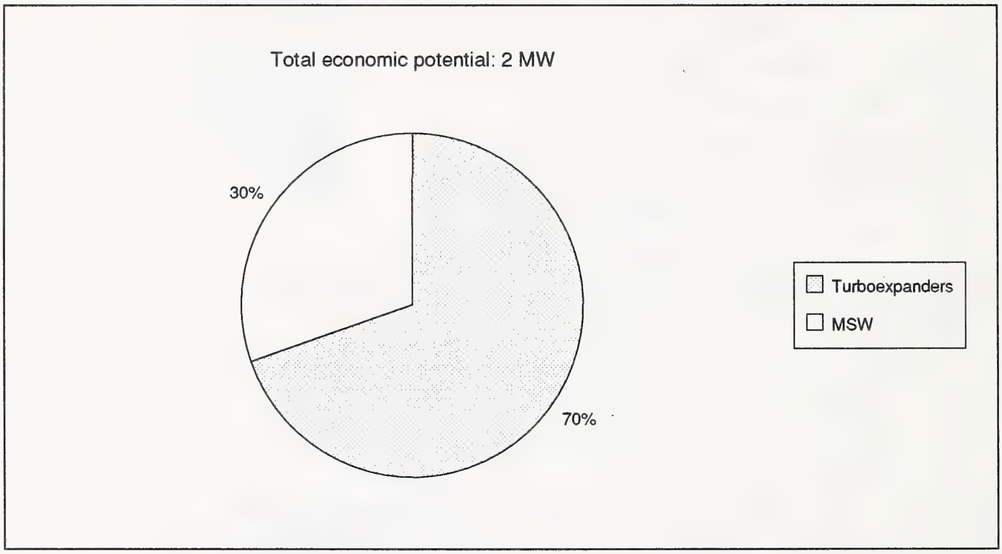

Figure 2-9. Base case 2005 economic potential - electric peak

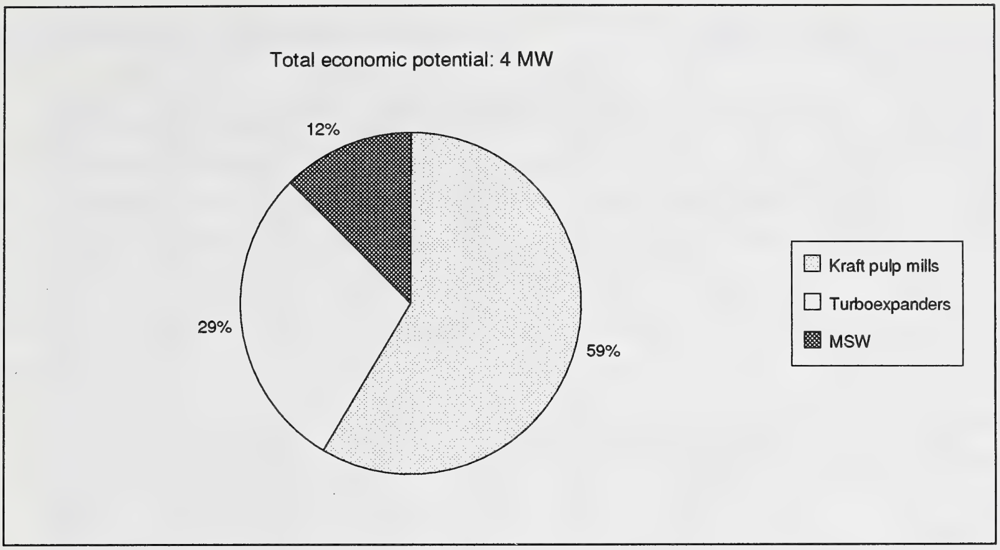

Figure 2-10. Base case 2005 economic potential - thermal peak

Predicted real gas rates in 2005 are much higher than those in 1992 while predicted real electric rates are the same. As a result, the only segments with economic potential in 2005 are those whose economic performance is insensitive to gas price. Kraft Pulp Mills and MSW plants use alternative fuels and thus are unaffected by the higher gas prices. Turboexpanders are assumed to use marketable natural gas only for preheating purposes, and so are less sensitive to natural gas prices than applications which burn solely marketable natural gas.

Tables 2-4 and 2-5 summarize the economic potential in each segment for each considered level of electric rates for both the 1992 and the 2005 scenario. Table 2-4 reports potential assuming cogeneration facilities size to peak electric load, while Table 2-5 reports potential assuming they size to peak thermal load.

Economic Potential (MW)	Size to Peak electric					
Electric rate	3¢/kWh		5.25¢/kWh		7.5¢/kWh	
Segment	1992	2005	1992	2005	1992	2005
Petrochemicals	6	0	208	170	365	753
Saw, panelboard, CTMP	0	0	0	1	14	16
Kraft pulp mills	0	0	53	75	111	155
Oil sands mining	8	0	96	97	135	237
Gas flares	0	0	33	33	87	87
Oil sands in-situ	0	0	28	12	59	103
Sour gas plants	5	0	54	43	80	103
MSW	0	1	3	3	5	6
Refineries	4	0	53	36	77	87
Sweet gas plants	1	0	16	13	24	32
Education	0	0	7	2	28	31
Hospitals	0	0	4	2	16	24
Turboexpanders	3	1	10	14	13	20
Food industry	0	0	0	0	8	4
TOTALS:	28	2	566	499	1021	1659

All numbers are rounded to the nearest MW. The rounded total may differ slightly from the sum of rounded segment contributions.

Table 2-4. Economic potential - size to peak electric load

Economic Potential (MW)	Size to Peak thermal					
Buyback rate	3¢/kWh		5.25¢/kWh		7.5¢/kWh	
Segment	1992	2005	1992	2005	1992	2005
Petrochemicals	55	0	704	945	1036	2393
Saw, panelboard, CTMP	0	0	0	0	14	16
Kraft pulp mills	2	3	194	271	412	577
Oil sands mining	24	0	274	348	374	670
Gas flares	0	0	33	33	87	87
Oil sands in-situ	0	0	57	30	122	232
Sour gas plants	10	0	111	107	152	206
MSW	0	1	3	3	5	6
Refineries	10	0	109	82	153	185
Sweet gas plants	4	0	52	49	70	100
Education	1	0	12	3	57	63
Hospitals	0	0	17	5	86	119
Turboexpanders	3	1	10	14	13	20
Food industry	0	0	1	0	18	17
TOTALS:	109	4	1577	1891	2598	4691

All numbers are rounded to the nearest MW. The rounded total may differ slightly from the sum of rounded segment contributions.

Table 2-5. Economic potential - size to peak thermal load

Existing Generation Capacity

The economic potential figures tabulated above reflect the attractiveness of implementing cogeneration given a particular scenario of rates. However, they do not reflect the fact that a significant amount of cogeneration is already in place in Alberta. Current on-site capacity in place in Alberta is shown in Table 2-6 below. Appendix D details this capacity by plant. Existing on-site generation is in excess of the economic potential we have identified for most segments for both the 1992 and the 2005 scenario.

Segment	On-Site Capacity (MW)
Oil sands mining	333
Petrochemicals	208
Kraft pulp mills	122
Gas Plants	34
Hospitals	23
Refineries	7
Food industry	6
Education	5
Other Commercial	6
Other Industrial	3
Other Misc.	2
TOTAL	749

Table 2-6. 1990 on-site generating capacity

Several reasons account for current potential being lower than current installed capacity. Some of the generation currently in place was installed at a time when electric rates and predicted growth in rates were much higher than they are now. Also, several of the current facilities faced concerns about transmission accessibility and reliability at remote locations or had access to fuels at below market rates. Finally, some of the facilities installed generation because they needed to dispose of waste, a motivation which is becoming less economically sound as environmental controls become more stringent. Thus, the prediction of low economic potential in both 1992 and 2005 relative to on-site generation actually implemented as of 1992 makes sense. Though there may exist certain motivations for installing cogeneration that cannot be adequately captured by the model employed for this study, it is not likely that such motivations will offset the economic considerations that are captured.

Incremental Economic Potential

The 1992 scenario illustrates that there is very little potential for additional cogeneration and generation from waste at 1992 rates and segment sizes as existing generation exceeds economic potential. Likewise, the 2005 scenario illustrates that there is little additional potential at 2005 rates and sizes. Potential is predicted to be low in 2005 because the high gas prices predicted for 2005 more than offset the greatly increased technical potential predicted to be available by this time. However, if a significant amount of segment growth (and hence growth in technical potential) occurs before gas rates reach the high levels predicted for 2005, some incremental potential could emerge between 1992 and 2005 which is not captured in the foregoing analyses.

To analyze incremental potential, we make several assumptions. First, we assume that all incremental cogeneration will be installed at new plants. Thus, the incremental technical potential is the difference between the technical potential in 2005 and the technical potential in 1992. Incremental technical potential defined in this way is tabulated in Table 2-7.

Segment	Size to Peak Electric	Size to Peak Thermal
Petrochemicals	836	2200
Oil sands in-situ	200	397
Oil sands mining	163	444
Kraft pulp mills	84	299
Gas flares	0	0
Sour gas plants	47	88
Saw, panelboard, CTMP	40	40
Refineries	32	63
Sweet gas plants	16	47
MSW	16	16
Turboexpanders	9	9
Hospitals	7	33
Food industry	11	25
Education	3	6
TOTAL	1464	3667

All numbers are rounded to the nearest MW. The rounded total may differ slightly from the sum of rounded segment contributions.

Table 2-7. Incremental technical potential (MW)

To determine incremental economic potential from this incremental technical potential, we must decide what rates are faced by potential cogenerators. Rather than assume a particular level of rates which all new facilities face, we will perform this analysis for the range of rates between the 1992 scenario and the 2005 scenario established previously. The situation most favorable to incremental potential is that in which all additional facilities are brought on line at 1992 gas rates. The most unfavorable situation is that in which new facilities face 2005 gas rates. The actual amount of incremental potential is likely to fall somewhere between these two scenarios. Figure 2-11 illustrates the incremental potential as a function of electric rate for both the 1992 and the 2005 gas rate scenarios and for both alternative cogeneration system sizing assumptions (peak electric and peak thermal sizing).

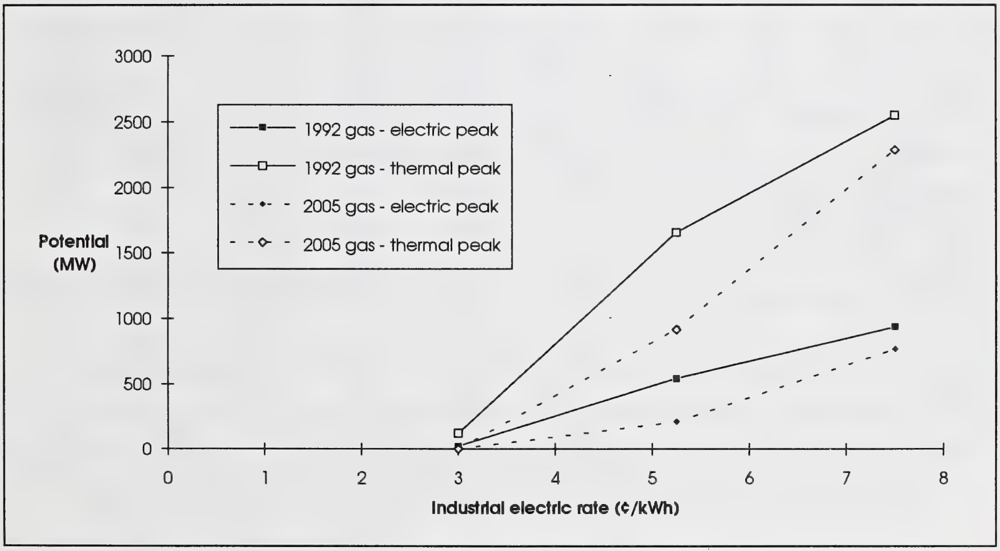

Figure 2-11. Incremental economic potential

The solid lines indicate what the incremental economic potential would be if all new facilities came on line at current 1992 gas rates. In this case, and at the predicted electric rate of 3¢/kWh (industrial), incremental economic potential is 22 MW if facilities size cogeneration to electric peak and 120 MW if they size to thermal peak. The dashed lines indicate what the incremental potential would be if all new facilities came on line at predicted 2005 gas rates. In this case, at 3¢/kWh, incremental economic potential is 1 MW whether facilities size to electric peak or to thermal peak.

Tables 2-8 and 2-9 tabulate the incremental economic potential for each individual segment. Table 2-8 assumes cogeneration facilities are sized to electric peak while Table 2-9 assumes they are sized to thermal peak. The electric rate shown in Table 2-8 is the industrial retail rate. Generation from waste segments are assumed to face an equal buyback rate while commercial segments are assumed to face a retail rate 2.25¢/kWh above the rate shown.

Economic Potential (MW)						
Retail/Buyback rate	3¢/kWh		5.25¢/kWh		7.5¢/kWh	
Segment	1992	2005	1992	2005	1992	2005
Petrochemicals	10	0	329	104	576	461
Oil sands mining	7	0	86	46	121	112
Oil sands in-situ	0	0	48	8	101	65
Kraft pulp mills	0	0	21	21	44	44
Gas flares	0	0	0	0	0	0
Sour gas plants	2	0	24	13	35	31
Refineries	1	0	16	8	24	21
Saw, panelboard, CTMP	0	0	0	0	2	2
Sweet gas plants	1	0	8	4	12	11
Turboexpanders	1	0	6	5	7	7
Hospitals	0	0	2	1	6	7
Education	0	0	1	0	3	3
Food industry	0	0	0	0	3	1
MSW	0	0	0	0	1	1
TOTAL	22	0	541	210	935	766

All numbers are rounded to the nearest MW. The rounded total may differ slightly from the sum of rounded segment contributions.

Table 2-8. Incremental economic potential - size to peak electric load

Incremental Economic Potential (MW)						
Buyback rate	3¢/kWh		5.25¢/kWh		7.5¢/kWh	
Segment	1992	2005	1992	2005	1992	2005
Petrochemicals	87	0	1111	579	1636	1465
Oil sands mining	22	0	244	164	334	316
Oil sands in-situ	0	0	99	19	210	147
Kraft pulp mills	1	1	77	77	165	165
Gas flares	0	0	0	0	0	0
Sour gas plants	4	0	49	33	66	63
Refineries	3	0	33	19	47	44
Saw, panelboard, CTMP	0	0	0	0	2	2
Sweet gas plants	2	0	26	16	35	33
Turboexpanders	1	0	6	5	7	7
Hospitals	0	0	7	2	33	33
Education	0	0	1	0	6	6
Food industry	0	0	1	0	6	5
MSW	0	0	0	0	1	1
TOTAL	120	1	1654	914	2548	2287

All numbers are rounded to the nearest MW. The rounded total may differ slightly from the sum of rounded segment contributions.

Table 2-9. Incremental economic potential - size to peak thermal load

Levelized Cost of Production

To conclude the summary, Tables 2-10 and 2-11 show the levelized cost of electricity production in each of the examined segments. Table 2-10 shows levelized costs for the 1992 and the 2005 scenario for systems sized to either electric peak or thermal peak assuming a 15 year financing term. Table 2-11 shows levelized costs assuming a 20 year financing term.

	Electric Peak		Thermal Peak	
Segment	1992	2005	1992	2005
Turboexpanders	2.1	2.5	2.1	2.5
Oil sands mining	2.5	3.6	2.4	3.2
Sour gas plants	2.6	3.7	2.4	3.3
Refineries	2.7	3.8	2.5	3.5
Petrochemicals	2.7	3.9	2.6	3.8
Sweet gas plants	2.7	3.8	2.4	3.3
Kraft pulp mills	3.3	3.3	3.2	3.2
Oil sands in-situ	3.5	4.8	3.3	4.5
MSW	3.7	3.7	3.7	3.7
Flare gas	4.1	4.1	4.1	4.1
Food industry	5.1	5.8	5.0	5.6
Hospitals	5.1	5.9	5.5	6.6
Education	5.2	6.1	5.4	6.4
Saw, panelboard, CTMP	5.3	5.3	5.3	5.3

All numbers are rounded to the nearest MW. The rounded total may differ slightly from the sum of rounded segment contributions.

Table 2-10. Levelized cost (¢/kWh) assuming 15 year term*

	Electric Peak		Thermal Peak	
Segment	1992	2005	1992	2005
Turboexpanders	1.9	2.3	1.9	2.3
Oil sands mining	2.4	3.4	2.2	3.1
Sour gas plants	2.5	3.5	2.2	3.1
Refineries	2.5	3.7	2.3	3.4
Petrochemicals	2.5	3.7	2.5	3.6
MSW	2.5	2.5	2.5	2.5
Sweet gas plants	2.6	3.6	2.2	3.1
Kraft pulp mills	3.0	3.0	2.9	2.9
Oil sands in-situ	3.3	4.5	3.1	4.2
Flare gas	3.9	3.9	3.9	3.9
Saw, panelboard, CTMP	4.8	4.8	4.8	4.8
Food industry	4.8	5.5	4.6	5.2
Hospitals	4.8	5.6	5.1	6.3
Education	4.9	5.8	5.0	6.1

All numbers are rounded to the nearest MW. The rounded total may differ slightly from the sum of rounded segment contributions.

Table 2-11. Levelized cost (¢/kWh) assuming 20 year term*

* The saw, panelboard, CTMP segment is assumed to have a tipping fee of $0/tonne. The MSW segment is assumed to have a tipping fee of $35/tonne.

3.0 Potential for Generation

This section contains a "bottom-up" analysis of the economic viability of cogeneration in a number of industrial and commercial segments. It begins with an explanation of the assumptions underlying the technical analyses and a description of the methods used to determine potential. The assumptions subsection is followed by a segment by segment analysis including a qualitative description, a technical analysis, and an analysis of economic potential for each segment. The cogeneration segments come first, followed by the generation from waste segments. The technical analysis of cogeneration segments is based largely on COGENMASTER, a state-of-the-art PC model of cogeneration economics developed for EPRI (Electric Power Research Institute) by SRC and used widely by utilities and government agencies in the United States and other countries. COGENMASTER is used to determine the economics of cogeneration for a "typical facility" in each segment. The output of COGENMASTER includes several measures of the economic attractiveness of installing cogeneration at that typical facility: payback period, internal rate of return (IRR), and rate of return on equity (ROE). The technical analysis of generation from waste segments is performed similarly using models tailored to each particular segment. For both cogeneration and generation from waste segments, a payback acceptance distribution is then used to translate payback into a measure of economic potential in the segment. The analyses incorporate various scenarios involving different levels of fuel prices, electric prices, and electric buyback rates in order to allow an analysis of sensitivities to these variables and in order to maintain the applicability of the analysis over time.

3.1 Analysis Framework and Assumptions

An overview of the economic and financial analysis is shown in Figure 3-1. The market segments that are analyzed were selected for the cogeneration opportunities they present. The choice of segments was based on a review of various studies and reports as well as conversations with industry experts.[3,4,5] Once the market segments were defined, a profile was prepared outlining the consumption of electricity and gas by segment. This profile is provided as Appendix A. The profile was developed by the Alberta Department of Energy with the cooperation of the electric and gas utilities in Alberta and representatives of a number of other industries. The profile presents a summary of the electric and gas use in each segment in the study and presents more detailed information on energy use and industry structure for the oil sands, gas plants, gas flares, refineries, petrochemical, wood products, and food processing segments. In this study, the profile was generally used as a check on more detailed, segment specific energy data from other sources. In some cases, the data was used as a crude measure of technical potential to screen out some facilities. These cases are noted in the discussions of the individual segments. The profile as a whole provides an excellent resource for the analysis of energy issues in Alberta.

A "representative facility" for each segment was defined based on the industry profile, interviews of industry experts, and other studies which are referenced in the discussions of individual segments. The characteristics of most interest in a representative facility are the electric and thermal loads, load profiles, and the size of the facility. For example, for the oil refinery segment, the average annual electric demand, average annual hourly steam consumption, and the crude oil production rate are used to define the typical oil refining facility. Oil refineries generally have a very high load factor. The hourly variations in their steam and electric demands are not significant. Therefore, it is sufficient to use average annual demands in characterizing this segment. On the other hand, the electric and thermal profiles in commercial establishments such as educational buildings and hospitals vary significantly from their

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[3]Acres International Limited. Cogeneration Potential In Ontario and Barriers to Its Development, Ontario Ministry of Energy: Canada, February 1987.

[4]Reinsch, A. E. & Battle, E. F. Industrial Cogeneration in Canada: Prospects and Perspectives, Canada Energy Research Institute: Calgary, March 1987. (ISBN 0-920522-41-6)

[5]Energy Efficiency Branch. A Discussion Paper on the Potential for Reducing Carbon Dioxide Emissions in Alberta: 1988-2005, Alberta Department of Energy: Canada, January 1991.

peak demands. Therefore, load shapes have been used to represent the typical facility in the commercial segments.

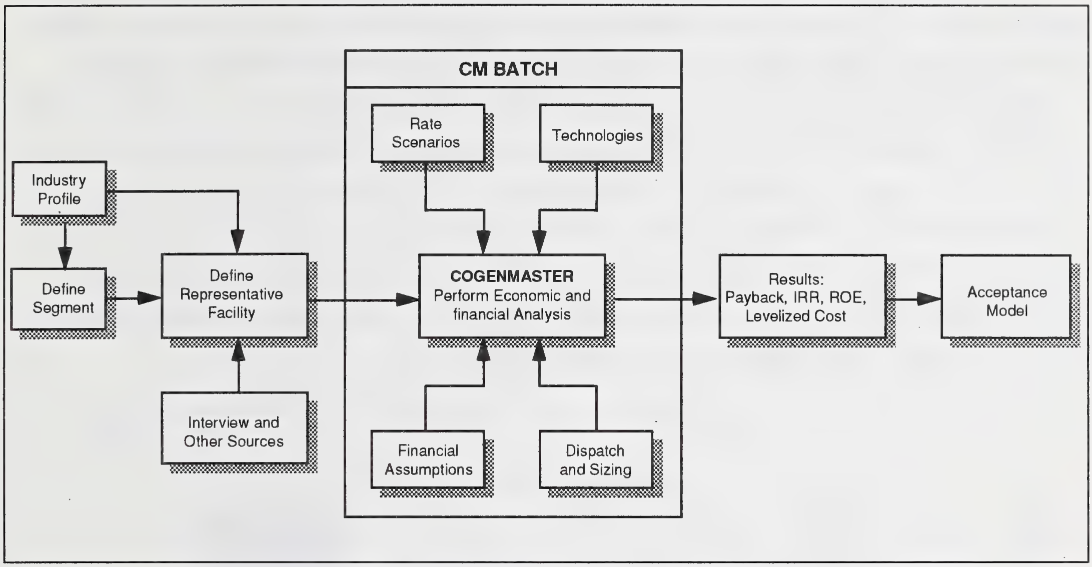

Figure 3-1. Overview of Model

The COGENMASTER model was used to perform the economic and financial analyses on the representative facility for most segments. Assumptions made on electric and fuel rates, technology characteristics, operating modes and sizing criteria, and financial parameters are explained below.

An analysis was performed for each possible combination of rate levels, technology, and operating mode for each segment. The CMBATCH software program was used to run multiple COGENMASTER analyses and prepare summary output tables. Results of the analyses include Cogeneration System Size, Simple Payback, Internal Rate of Return, Return on Equity, and Levelized Costs. These results are used in an Acceptance Model to determine the potential of cogeneration / generation from waste for each segment.

Rates and Fuel Cost

Fuel cost is always assumed in this analysis to be incremental to thermal requirements. All rates in this analysis are presented in 1992 real rather than nominal dollar amounts. Real electric, gas, and other fuel rates were chosen to span a wide range in order to allow for extreme events (growth in excess of inflation) and to enable threshold prices to be found in all but the most unlikely scenarios. The lowest rates have been chosen to correspond to current levels. The highest rates correspond to roughly 5% real growth through 2005. Electric rates are modeled as energy only rates in order to simplify the analysis. Electric buyback rates are chosen to span a larger range so that any conceivable policy regarding buyback rates can be analyzed. Electric rates investigated are depicted graphically in Figure 3-2.

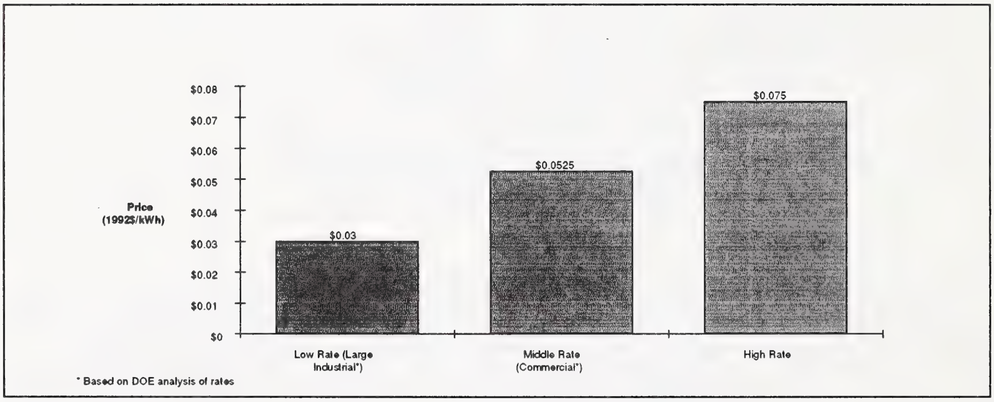

Figure 3-2. Actual and investigated electric rates

The range of wood residue costs is chosen to encompass the conceivable range of costs through 2005. The analysis of wood residue generation is done using oven dry rather than green tonnes. We chose oven dry tonnes in order to conform to the practice employed in other studies on wood residue.

Because natural gas is the predominant fuel for large scale cogeneration, this analysis assumes that natural gas is the fuel used by cogeneration installations. (It is assumed that gas is not used in generation from waste.) Gas rates investigated are depicted graphically in Figure 3-3, below. The gas rate used is for a firm, domestic, wellhead price. Some cogenerators may have access to fuel gas or other sources with

a lower price; others may pay a higher delivered, retail price. The investigators felt that the rate used was a good indicator of typical burner tip prices. Sensitivity to gas prices is performed in later sections.

The fuel for the forest industry segments is wood waste, and the fuel for the municipal solid waste (MSW) segment is municipal waste. Negative costs for these rates represent the costs of alternate disposal.

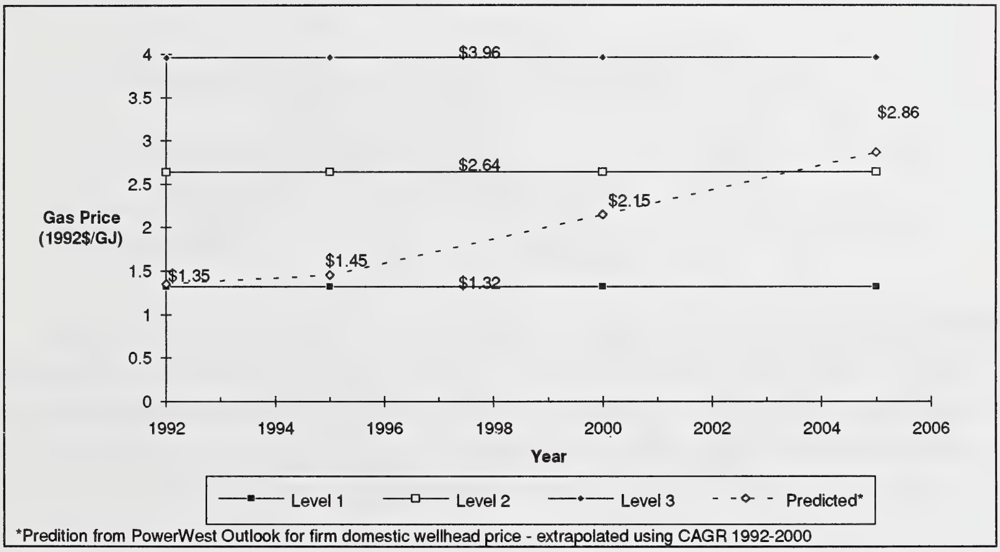

Figure 3-3. Predicted and investigated gas rates

The entire analysis is conducted using real rather than nominal dollar amounts. Thus, the three rates investigated could be interpreted as escalating at 4.5%, the assumed average rate of inflation through 2005. The analysis maintains a constant real gas price over the life of a cogeneration project. Thus, it is assumed that gas contracts will be written such that the escalation in gas prices matches overall inflation. However, it is assumed that the real gas price contracted will increase over time so that contracts written in 2005 will be for a higher real gas price than contracts written in 1992.

Rates considered are tabulated in Tables 3-1 through 3-4 below.

R1	\$0.03/kWh
R2	\$0.0525/kWh
R3	\$0.075/kWh

Table 3-1. Electric rates

A	\$0.05/m^3 (\$1.32/GJ)
B	\$0.10/m^3 (\$2.64/GJ)
C	\$0.15/m^3 (\$3.96/GJ)

Table 3-2. Gas rates

B1	\$0.01/kWh
B2	\$0.03/kWh
B3	\$0.0525/kWh
B4	\$0.075/kWh

Table 3-3. Electric buyback rates

W1	\$-10/oven dry tonne	(\$-0.50/GJ)
W2	\$0/oven dry tonne	(\$0/GJ)
W3	\$10/oven dry tonne	(\$0.50/GJ)

Table 3-4. Wood residue rates

M1	$20/tonne
M2	$35/tonne
M3	$50/tonne

Table 3-5. MSW tipping fees

Technologies

The following technologies have been considered in this study.

1. Gas engine with heat recovery
2. Gas turbine with waste heat recovery boiler
3. Steam turbine
4. Combined Cycle.

Not all of the technologies listed above will be applicable to every segment that is analyzed. The technologies have different abilities to meet steam loads at different levels of steam pressure and quality, and some may not be able to meet the process requirements of a particular application. Also, some of these technologies may not be available in the desired size range. Systems are designed to match electric and thermal loads and are based on the performance of average equipment. Some operations may be able to obtain higher efficiencies. Advanced or future technologies were not considered.

The characteristics of each of the four technologies are given in Table 3-6.

CHARACTERISTICS OF COGENERATION TECHNOLOGIES

Design point values

	Steam Pressure, psi	Electrical Efficiency	Thermal Efficiency	Combined Efficiency	Fuel Use mmBtu/MWh	MWh per MM lb Steam	Steam '000 lb/MWh
Boiler		--	0.9	0.9	--	--	--
Gas Engine with Heat Recovery	*	0.32	0.52	0.84	10.666	--	--
Gas Turbine with Heat Recovery Boiler	15	0.231	0.565	0.796	14.775	120	8.35
	450	0.236	0.496	0.732	14.462	139	7.17
	2200	0.24	0.45	0.69	14.221	156	6.4
Steam Turbine	15	0.27	0.69	0.96	12.641	115	8.72
	150	0.17	0.77	0.94	20.076	65	15.46
	450	0.12	0.83	0.95	28.442	42	23.61
Combined Cycle	15	0.269	0.548	0.817	12.688	144	6.95
	150	0.211	0.598	0.809	16.175	103	9.67
	450	0.165	0.64	0.805	20.685	76	13.24

*Thermal energy recovered in the form of hot water.

Source: Synergic Resources Corporation, Cogenmaster-A Model for Evaluating Cogeneration Options, Prepared for the Electric Power Research Institute, EM-6102, pp2-2 to 2-3, Palo Alto, California, December 1988

Table 3-6. Characteristics of cogeneration technologies

Operating Mode and Sizing Criteria

Two operating modes have been considered -- *Buy-All/Sell-All* and *Buy-Deficit/Sell-Excess*. The price of electricity plays a decisive role in determining which strategy to follow and how to size the electric generation. If the buyback price of electricity is higher than the retail price of electricity, under a payback or IRR criterion the facility will opt to operate the cogeneration system in buy-all/sell-all mode. However, if the retail price exceeds the buyback price, the facility will choose to operate the cogeneration system in buy-deficit/sell-excess mode. Each of the applicable technologies have been evaluated in both operating modes. The electric generating portion of cogeneration systems are usually sized to meet the peak or base thermal or electric load. Figure 3-4 illustrates the different criteria that may be used to size cogeneration systems.

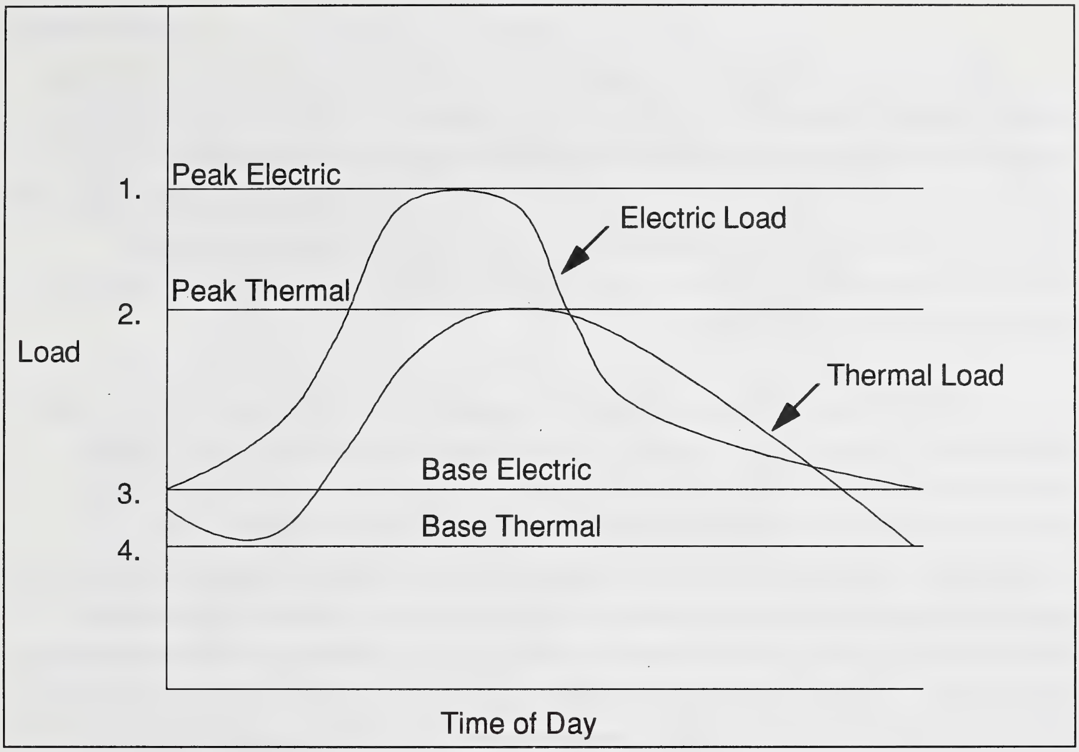

Figure 3-4. Alternative cogeneration system sizing criteria

In the buy-all/sell-all mode (buyback price higher than retail price), using a payback or IRR criterion, it is more economically attractive to size the electric generation portion of the cogeneration system to take advantage of the peak thermal load and generate as much electricity as possible. Conversely, in the buy-deficit/sell-excess mode (retail price higher than buyback price), it is more attractive to size the system to the smaller of the peak electric load and the peak thermal load, and to avoid selling to the utility.

If a Net Present Value criterion were used in the analysis, sizing would depend only on the relationship between buyback price and the marginal cost of added production. Units would be sized to take advantage of the full thermal load anytime the buyback price was high without consideration of the relative retail price. The potential based on an NPV analysis would lie between the two extremes being close to the higher buy-all/sell-all level when buyback prices are high and closer to the buy-deficit/sell-excess level when buyback prices are low.

Since optimal sizing of the cogeneration system is dependent on the operating mode, a different technology may be the most economic in each of the two operating modes, (i.e., it is conceivable that the technology that is most economic in the buy-all/sell-all mode may not be the most economic in the buy-deficit/sell-excess mode). Therefore, each combination of technology and operating mode was analyzed. However, only the analyses based on the optimal choices for technology and operating mode are presented in this report.

In the analysis of each segment, it is assumed that mode, sizing, and technology decisions are made optimally based on the level of fuel, retail electric, and buyback electric rates. Different systems are assumed to be implemented for different rate scenarios. For those rate scenarios where buyback price exceeds retail price, a system sized to peak thermal load and operating in buy-all/sell-all mode (using the technology optimal for this mode and this application) is assumed. For those rate scenarios where retail price exceeds buyback price, a system sized to the smaller of the peak electric and the peak thermal loads, operating in the buy-deficit/sell-excess mode is assumed. In this latter rate scenario, the preferred strategy will be to meet one's own load and not generate any excess electricity to sell to the utility. Therefore, the system is sized to the smaller of peak electric and peak thermal loads.

Reliability

The COGENMASTER analyses have been performed under the assumption that the cogeneration systems will be available and reliable at all times. The risks associated with less than adequate reliability and availability will be addressed in the risk analysis section of this report. Given this assumption on reliability, it is assumed that the cogeneration operations do not pay for standby power.

Capital Costs

The capital costs of cogeneration systems can vary widely based on conditions at the site. The analyses of standard installations in this report have been performed using the average costs shown in Table 3-7[6].

Gas engine with heat recovery	$2,000/kW
Gas turbine with heat recovery	$1,000/kW
Steam turbine	$1,500/kW
Combined cycle	$1,200/kW

Table 3-7. Capital cost for standard installations

The actual capital costs faced by a given facility may be lower or higher than the costs used in this analysis. The intention is that the costs in this analysis are typical. The tabulated costs are based on standard, new installations (in general, retrofit costs would be higher) and are increased wherever non-standard conditions exist. For example, the high steam pressures required at the in-situ oil recovery sites cannot be supplied by standard waste heat recovery boilers. A cost of $1,500/kW is assumed for this application. Also, if a fuel other than natural gas is used, the cost of the boilers for steam turbine systems may increase to two to four times the cost given here. For example, the cost of a 20MW wood fired plant is estimated to be $2,300/kW.[7] Capital costs do not reflect economies of scale, except that the expensive gas engine technology is not appropriate for large installations.

Capital costs in this analysis are incremental to equipment meeting a facility's thermal requirements. It is assumed that redundant facilities for meeting thermal loads are maintained. The capital costs in this analysis do not consider the cost of transmission lines. These costs may be as high as $1,000,000 per mile. Transmission costs may either favor or discourage cogeneration. We will indicate the sectors most likely to be sensitive to transmission costs and examine these impacts. Incremental

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[6]The average costs have been taken from the Proceedings of the Industrial Energy Systems Course, University of Wisconsin, April 29 - May 3, 1991. The cost of a 20MW gas turbine cogeneration plant is estimated at US$18 million (US$910/kW or C$1,000/kW) in the EPRI report entitled Future Cogeneration Technologies, prepared by SFA Pacific, Inc., EPRI CU-6795, May 1990.

[7]"Woodlands Technology and Residue Disposal/Utilization", Proceedings of the Forestry Conference '91, Edmunton, Alberta.

transmission costs will be relatively low for generation near the grid and costs can be shared with the utility in many cases. If the cogenerator installs a system with capacity in excess of on-site requirements, the incremental cost of the transmission line would generally be considered part of the cogeneration system cost. For facilities in Alberta that are located quite far from the grid, self-generation without a connection to the grid may save the high cost of transmission lines. In these areas, cogeneration or generation from waste will have a further economic incentive.

Capital costs may include[8]:

- Cost of equipment - fuel handling, boiler, engine, turbine, generator, heat exchangers, heat recovery boilers, piping and electrical hardware to interface with the grid
- Installation of equipment
- Site preparation
- Land and buildings
- Design fees
- Short-term interest for construction financing

Financial Assumptions

The following financial assumptions have been made in the internal rate of return, return on equity, and levelized cost computations:

- The cogeneration facility will be owned by the thermal host facility. Thus, we will deal only with incremental capital costs.
- Eighty percent of the capital cost will be eligible for accelerated depreciation under Class 34 rules (projects meet the efficiency requirements). The following schedule is applied: Year 1 - 25%, Year 2 - 50%, and Year 3 - 25%. The remaining 20 percent of the capital cost will be depreciated as a double declining balance (i.e. 40% depreciation on the declining balance) over 5 years.

[8]All costs are incremental to needs for thermal production, so some of these costs do not apply to certain segments

- Eighty percent of the capital cost will be financed by a 7.5 percent real loan (inflation adjusted from 12 percent) with a 12 year term. Gas engine cogeneration projects are the sole exception, being financed with a 5 year term because of the necessity of major overhauls every 4 to 5 years. The remaining 20 percent of the capital cost will be the equity of the host facility
- The economic life of the cogeneration systems is 20 years
- The discount rate for levelized cost is 7% (inflation adjusted from 11.5%)
- Levelized costs have been computed for both 15 and 20 year terms[9]
- The effective tax rate is 44%
- All costs are in real 1992 dollars. No escalations have been applied.
- The model implicitly assumes that the facility has sufficient income from other sources to offset any loss attributable to the cogeneration project and carry forward of losses for taxes is considered.

Model of Economic Potential

The word "potential" can mean many different things. In this study, what we mean by economic potential is the amount of cogeneration that will eventually be in place if cogeneration decision makers base their decisions on certain specified criteria. The word "eventually" is very important. In this definition it marks the key difference between "potential" and "implemented" power generation. Economic potential is the amount of cogeneration that will eventually be in place, whereas implemented generation is the amount of cogeneration in place at a particular time. The concept capturing the difference between economic potential and implemented generation is "penetration", the fraction of economic potential expected to be implemented at any given time. Penetration will be treated separately in this paper in the section on Sensitivity to Risk and Other Factors.

To determine economic potential, we apply a distribution that relates project payback to the percent of installations that will eventually implement the project. The assumption underlying the use of a distribution is that different firms make their

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[9]The levelized cost is the present value of the incremental capital cost plus the incremental fuel cost plus incremental O&M cost, divided by the present value of the cogenerated electricity. Thus electricity generation bears a relatively low fuel cost.

investment decisions based on different investment criteria, and that when many firms are considered together, their investment criteria are distributed in a predictable way. For segments with very few installations, it makes less sense to apply a distribution for calculating potential. However, for the sake of consistency, they are treated identically in this analysis.

The distribution of eventual acceptance with respect to payback used for segments with many installations is taken from an amalgam of research by SRC on intended investment. The distribution is shown in Table 3-8 and depicted in Figure 3-5.[10]

Payback (Years)	Percent Accepting
0.0	100.0%
0.5	91.0%
1.0	82.0%
1.5	77.8%
2.0	73.5%
2.5	62.0%
3.0	50.5%
3.5	39.3%
4.0	28.1%
4.5	25.9%
5.0	23.6%
5.5	14.3%
6.0	5.0%
6.5	4.8%
7.0	4.6%
7.5	4.0%
8.0	3.3%
8.5	2.3%
9.0	1.2%
9.5	1.2%
10.0	1.2%
10.5	0.6%
11.0	0.0%

Table 3-8. Payable acceptance distribution

[10]SRC. Payback Acceptance Characteristics Working Paper. prepared for the New York State Energy Research and Development Authority, April 1991.

This payback distribution is based on responses from 584 industrial investment decision-makers to questions about the payback required to make an energy conserving investment. The data is aggregated from several different studies by SRC that were conducted in the U.S. from 1981 to 1989. These studies were used because no similar studies specific to Alberta or Canada were identified. However, the paybacks were calculated based on Canadian financial data and tax laws, and the results should reflect these factors. As noted, the data is based on industrial investment decision-makers. If independent developers have significantly different decision criteria, the curve may not be appropriate for their segment of the market. The data does not reflect any time for penetration of technologies; therefore, the economic potential should be considered a long run potential. As stated previously, penetration is discussed more fully in the section on sensitivity to risk and other factors.

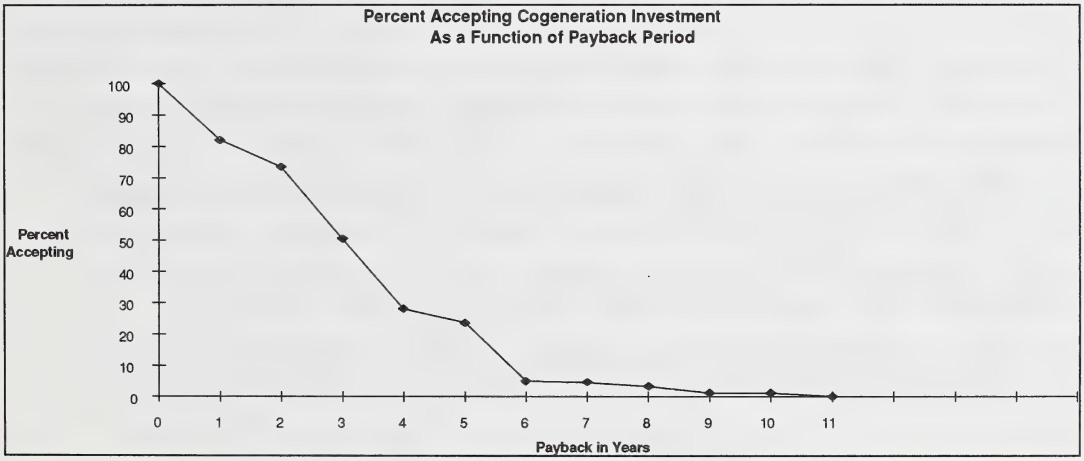

Figure 3-5. Payback acceptance distribution

3.2 Oil Sands Mining

Alberta contains the most extensive deposits of oil sands in the world. As the price of oil rises with diminishing oil reserves worldwide, the exploitation of these oil sands becomes increasingly economic. Consequently, the Alberta oil sands industry and the potential for cogeneration in this industry are growing. In 1990, oil sands were responsible for 25% of Alberta's production of crude oil and its equivalent, as compared with 17% in 1985.[11] Oil sands operations in Alberta include both in-situ projects producing non-upgraded bitumen and integrated mining projects producing synthetic crude oil (SCO). These two types of operations have very different thermal requirements and so are treated as separate segments in the technical analysis of cogeneration potential.

Oil sands mining operations integrate surface mining of oil sands, extraction of bitumen from the sands, and upgrading of bitumen to SCO at a single site. There are currently two integrated mining operations in Alberta, one operated by Suncor and one by Syncrude. The Suncor plant currently produces 62,932 barrels of SCO per day (based on the first half of 1991), while the Syncrude plant produces 151,210 barrels per day. Both of these plants currently generate electricity on site. Suncor has 64MW of on site generation capacity while Syncrude has 269MW of capacity.[12] Significant growth is expected in this industry. Production of SCO from mining operations is predicted by the ERCB to rise from approximately 12 million m^3 in 1990 to approximately 20 million m^3 by the year 2000 - a compound annual growth rate of approximately 5%.[13]

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[11]ERCB. Energy Requirements in Alberta 1991-2005, Energy Resources Conservation Board: Calgary, 1991.

[12]ERCB. 1991 Annual Electricity Statistics Report, Energy Resources Conservation Board: Calgary, 1991.

[13]ERCB. Energy Requirements in Alberta 1991-2005, pp 30-32. Energy Resources Conservation Board: Calgary, 1991.

Representative facility characteristics

The representative surface mining facility has a production rate of 80,000 barrels per day[14]. The average steam requirement for this facility is 1.3 million lb/hr at a pressure of 50 psi. The average electric requirement of the facility is 65 MW.

The steam requirements of this facility can be met by a number of different technologies. The analysis was performed using gas turbine, steam turbine, and combined cycle technologies.

Results of COGENMASTER analysis

Of the three technologies evaluated, the gas turbine was the most economical because of its lower capital cost. The other two technologies had slightly longer paybacks. The results of the COGENMASTER analysis appear in Tables 3-9 through 3-11 below and are summarized in Appendix B.

Table 3-9 illustrates the systems considered for the two alternative operating modes.

Operating Mode	Cogeneration Sizing Strategy	System Type	Capacity (MW)
Buy All/Sell All	**Thermal Peak**	**Gas Turbine w/ Heat Recovery**	**177.42**
Buy Def./Sell Excess	Electric Peak	Gas Turbine w/ Heat Recovery	65.00

Table 3-9. System description - Oil Sands Mining

The thermal requirements of the site are so large that a 177 MW gas turbine cogeneration system could be supported and a significant amount of electricity could be sold back to the utility.

Scaling the representative facility up to the size of the segment requires 2.8 representative facilities in 1992 and 5.3 facilities in 2005. Thus, total technical potential

[14]Based on discussions with oil industry experts in Alberta.

is 497 MW in 1992 and 940 MW in 2005 assuming buy-all/sell-all mode. Technical potential is 182 MW in 1992 and 345 MW in 2005 assuming buy-deficit/sell-excess mode.

The results of COGENMASTER runs measuring economic attractiveness of the proposed cogeneration investment are shown in terms of simple payback, internal rate of return, and rate of return on equity in Table 3-10 below. The shaded regions in this table indicate price scenarios for which the cogeneration plant is operated in the buy-all/sell-all mode.

N. Gas ->	A:-$0.05/cu.m. ($1.32/GJ)				B:-$0.10/cu.m. ($2.64/GJ)				C:-$0.15/cu.m. ($3.96/GJ)			
Buyback ¢/kWh->	1.00	3.00	5.25	7.50	1.00	3.00	5.25	7.50	1.00	3.00	5.25	7.50
Electric Rate	Simple Payback (Years)											
R1: 3.0¢/kWh	7.0	6.3	2.8	1.8	18.4	12.3	3.6	2.1	20.0	20.0	5.0	2.5
R2: 5.25¢/kWh	2.9	2.9	2.8	1.8	4.0	4.0	3.6	2.1	6.2	6.2	5.0	2.5
R3: 7.5¢/kWh	1.9	1.9	1.9	1.8	2.2	2.2	2.2	2.1	2.8	2.8	2.8	2.5
	Internal Rate of Return											
R1: 3.0¢/kWh	0.10	0.11	0.25	0.38	0.00	0.03	0.20	0.33	0.00	0.00	0.15	0.28
R2: 5.25¢/kWh	0.24	0.24	0.25	0.38	0.18	0.18	0.20	0.33	0.11	0.11	0.15	0.28
R3: 7.5¢/kWh	0.37	0.37	0.37	0.38	0.31	0.31	0.31	0.33	0.26	0.26	0.26	0.28
	Rate of Return on Equity											
R1: 3.0¢/kWh	0.46	0.53	1.17	1.71	0.00	0.01	0.94	1.50	0.00	0.00	0.69	1.29
R2: 5.25¢/kWh	1.12	1.12	1.17	1.71	0.86	0.86	0.94	1.50	0.54	0.54	0.69	1.29
R3: 7.5¢/kWh	1.67	1.67	1.67	1.71	1.43	1.43	1.43	1.50	1.18	1.18	1.18	1.29

Table 3-10. Economics of cogeneration - Oil Sands Mining

Figures 3-6 and 3-7 depict the IRR results from Table 3-10 graphically for the buy-deficit/sell-excess mode and the buy-all/sell-all mode respectively.

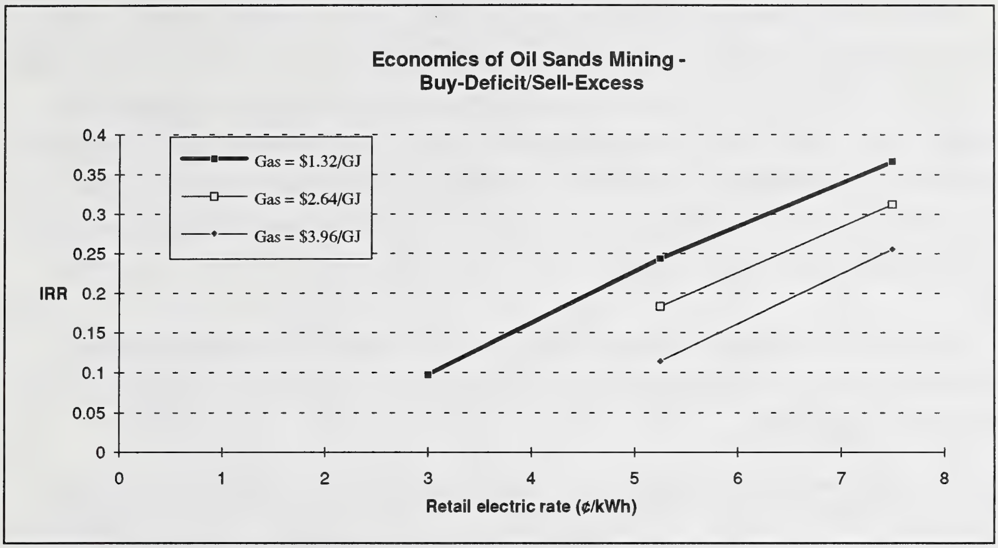

Figure 3-6. Economics - Buy-deficit/sell-excess mode - Oil Sands Mining

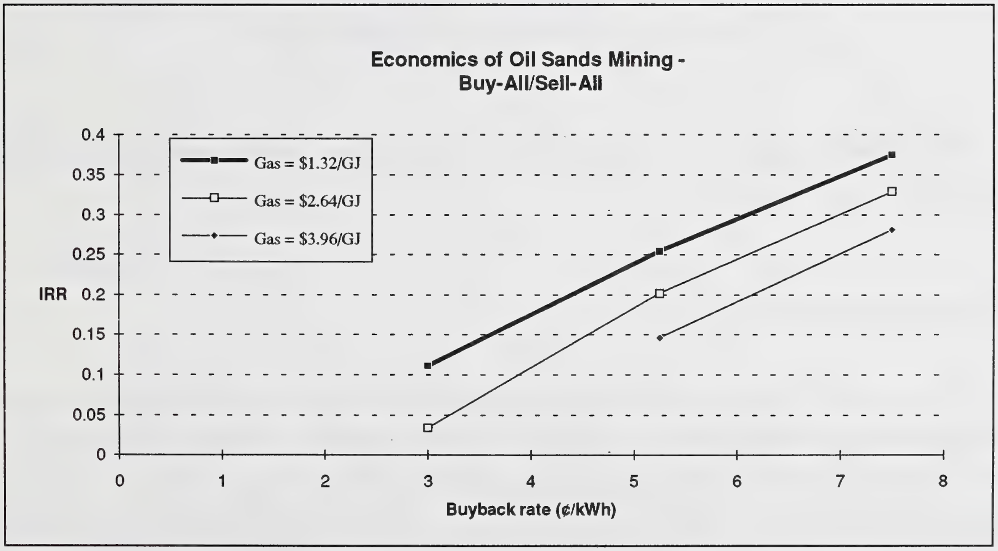

Figure 3-7. Economics - Buy-all/sell-all mode - Oil Sands Mining

Higher gas prices tend to make the economics of the system poorer. If the electric purchase rate exceeds the buyback rate, the system is sized to electric peak (no electricity will be sold to the utility), and therefore the system's economics are sensitive to the electric rate but not the buyback rate. Conversely, in the case where the buyback rate exceeds the purchase rate, the system's economics are sensitive to the buyback rate but not the electric rate, since all electricity generated will be sold to the utility under these circumstances.

Table 3-11 shows the levelized project cost for each of the two operating mode/sizing options, for two alternative lengths of financing term, and for each of the three levels of gas costs.

N. Gas ->	A:-$0.05/cu.m. ($1.32/GJ)		B:-$0.10/cu.m. ($2.64/GJ)		C:-$0.15/cu.m ($3.96/GJ)	
Discount Rate: 7%	Levelized Cost (¢/kWh)					
Term: 15 yrs	2.54	**2.36**	3.55	**3.24**	4.56	**4.12**
Term: 20 yrs	2.37	**2.20**	3.39	**3.08**	4.40	**3.96**

Table 3-11. Levelized cost - Oil Sands Mining

The levelized cost of electricity ranges from 2.2 to 4.6¢ /kWh depending on the cost of gas.

Economic Potential

The percent of representative facilities that will find the cogeneration investment attractive was calculated based on the payback numbers from Table 3-10 using the payback acceptance distribution explained in the Method of Analysis Section. Percent accepting is shown as a function of electric rate in Figure 3-8 for buy-deficit/sell-excess mode and as a function of buyback rate in Figure 3-9 for buy-all/sell-all mode.

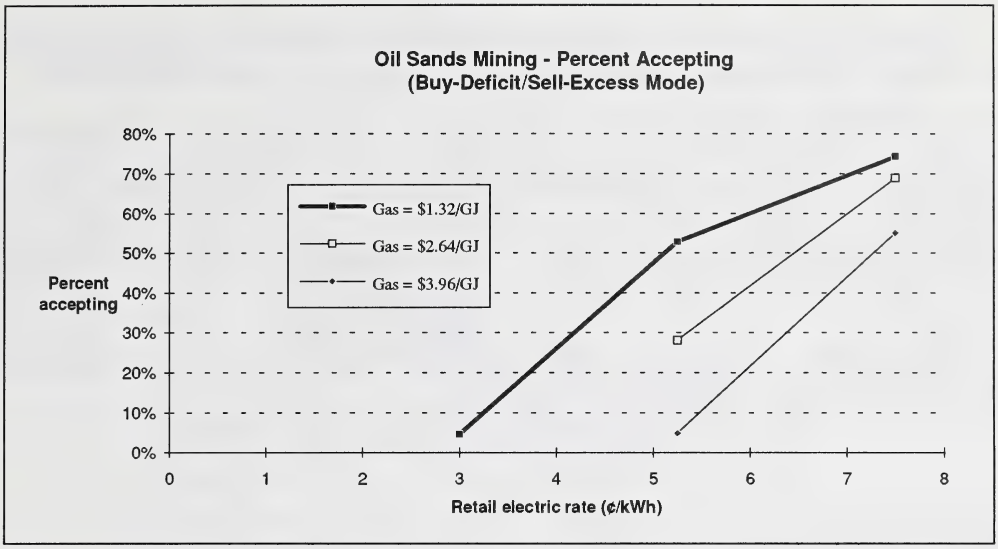

Figure 3-8. Percent accepting - Buy-deficit/sell-excess mode - Oil Sands Mining

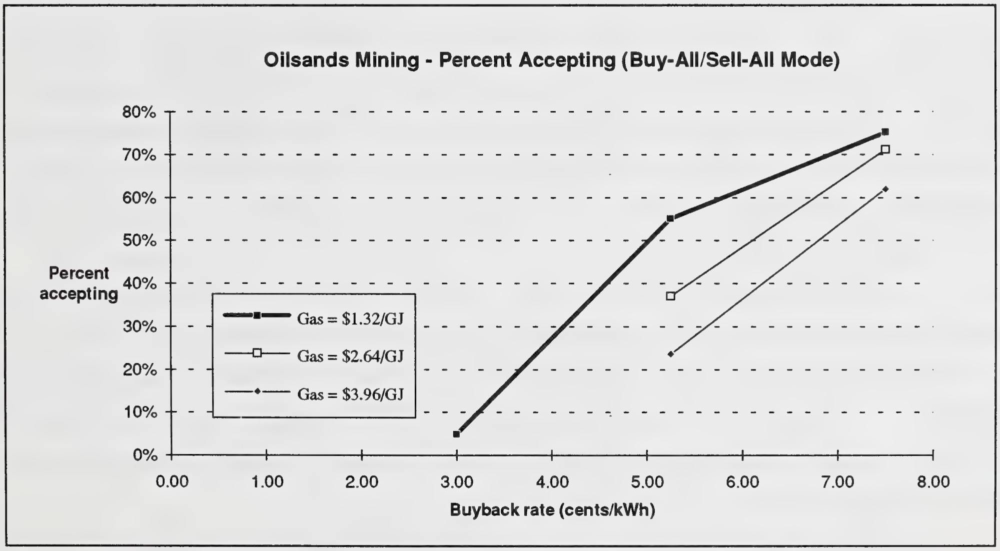

Figure 3-9. Percent accepting - Buy-all/sell-all mode - Oil Sands Mining

Table 3-12 summarizes the calculation of technical and economic potential for the 1992 and 2005 scenarios and provides a comparison to current implementation.

	1992		2005	
	Electric Peak	Thermal Peak	Electric Peak	Thermal Peak
Number of Facilities	2.8		5.3	
Representative Capacity (MW)	65.00	177.42	65.00	177.42
Technical Potential (MW)	182.00	496.78	344.50	940.33
Percent Accepting	4.6%	4.9%	0.0%	0.0%
Economic Potential (MW)	8.37	24.20	0.00	0.00
1990 Implementation (MW)	333.00			

Table 3-12. Base case summary - Oil Sands Mining

Discussion of Results

Under either buy-deficit/sell-excess mode or buy-all/sell-all mode, only about 5% of technical potential is expected to be economic in the 1992 scenario of low gas and electric prices. None of the technical potential is expected to be economic in the 2005 scenario of higher gas prices. Two factors may account for the high level of existing cogeneration in this segment. First, existing generation in this segment was installed in the 1970's and 1980's when the real price of electricity and the expected escalation in this price were much higher. Second, the segment currently uses fuel gas rather than pipeline gas in its operations. Third, the price of this gas may be significantly lower than the price used in this analysis. A lower gas price was not used in this segment for several reasons; these are: the fuel gas is lower quality and may be subject to environmental constraints in the future, the Terms of Reference stated that gas was to be analyzed with royalties, and fuel gas costs were not available. Finally, this segment may have installed cogeneration largely in order to dispose of waste, a motivation not captured in our analysis.

3.3 Oil Sands In-Situ

In-situ projects are defined as those projects where the bitumen deposit is too deep to be economically recovered by surface mining techniques. Instead, the bitumen is recovered by in-situ thermal techniques (typically steam injection) or by primary production. There are eight major in-situ facilities in production in Alberta as shown in Table 3-13 below.

Project	**Bitumen Production (bbls/day)**[15]
Esso Cold Lake	69,129
Shell Peace River	10,926
Amoco Elk Point	8,969
BP/PC Wolf Lake	6,965
Amoco Lindbergh	5,085
Suncor Burnt Lake	516
Murphy Cold Lake	326
Amoco Primrose	150
TOTAL	102,166

Table 3-13. Production by major Oil Sands In-Situ facilities

None of these projects cogenerate as of 1990[16]. The ERCB predicts that production of non-upgraded bitumen from in-situ projects will rise from its present (1990) level of 7.7 million m^3 to 16.3 million m^3 by the year 2000. This corresponds to a compound annual growth rate of approximately 7.8%.[17]

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[15]Production in average barrels per day for first half of 1991.

[16]ERCB. 1991 Annual Electricity Statistics Report, Energy Resources Conservation Board: Calgary, 1991.

[17]ERCB. Energy Requirements in Alberta 1991-2005, Energy Resources Conservation Board: Calgary, 1991.

Representative facility characteristics

The representative in-situ project for the purpose of this analysis has a recovery rate of 20,000 barrels per day. The average steam requirement of 275,000 lb/hr, is quite large. Also, the steam needs to be supplied at a high pressure, 15 MPa or 2200 psi, with an 80% quality. The average electric requirement of this project is of the order of 20 MW, with a very high load factor.

The requirement of high pressure steam (on the order of 15 MPa) at 80% quality limits the number of cogeneration technologies that can be considered. The only applicable technology is a gas turbine topping cycle. The exhaust of the gas turbine is passed through a waste heat recovery boiler that can generate steam at the required pressure and quality. Since this is a non-standard application, the cost of the waste recovery boiler will be higher. An installed cost of $1,500/kW has been used for this analysis. Costs have been projected for such applications that are as low as $750/kW. However, given the high pressure and quality requirements, we feel that $1,500/kW will be a more typical installed cost. A sensitivity analysis for lower capital costs is shown in the section on Sensitivity to Risk and Other Factors.

Results of COGENMASTER analysis

The results of the COGENMASTER analysis appear in Tables 3-14 through 3-16 below and are summarized in Appendix B.

Table 3-14 illustrates the systems considered for the two alternative operating modes.

Operating Mode	Cogeneration Sizing Strategy	System Type	Capacity (MW)
Buy All/Sell All	Thermal Peak	Gas Turbine w/ Heat Recovery	39.69
Buy Def./Sell Excess	Electric Peak	Gas Turbine w/ Heat Recovery	20.00

Table 3-14. System description - Oil Sands In-Situ

Scaling the representative facility requires 5.8 representative facilities in 1992 and 15.8 facilities in 2005. Assuming a system sized to thermal peak, this corresponds

to a technical potential of 230 MW in 1992 and 627 MW in 2005. Assuming a system sized to electric peak, technical potential is 116 MW in 1992 and 316 MW in 2005.

The results of COGENMASTER runs measuring economic attractiveness of the proposed cogeneration investment are shown in terms of simple payback, internal rate of return, and rate of return on equity in Table 3-15 below. The shaded regions in this table indicate price scenarios for which the cogeneration plant is operated in the buy-all/sell-all mode.

N. Gas ->	**A:-$0.05/cu.m. ($1.32/GJ)**				**B:-$0.10/cu.m. ($2.64/GJ)**				**C:-$0.15/cu.m. ($3.96/GJ)**			
Buyback ¢/kWh->	1.00	3.00	5.25	7.50	1.00	3.00	5.25	7.50	1.00	3.00	5.25	7.50
Electric Rate	**Simple Payback (Years)**											
R1: 3.0¢/kWh	13.6	12.1	4.7	2.9	20.0	20.0	6.7	3.6	20.0	20.0	12.0	4.7
R2: 5.25¢/kWh	4.9	4.9	4.7	2.9	7.6	7.6	6.7	3.6	17.0	17.0	12.0	4.7
R3: 7.5¢/kWh	3.0	3.0	3.0	2.9	3.8	3.8	3.8	3.6	5.3	5.3	5.3	4.7
	Internal Rate of Return											
R1: 3.0¢/kWh	0.03	0.04	0.16	0.25	0.00	0.00	0.10	0.20	0.00	0.00	0.04	0.16
R2: 5.25¢/kWh	0.15	0.15	0.16	0.25	0.09	0.09	0.10	0.20	0.00	0.00	0.04	0.16
R3: 7.5¢/kWh	0.24	0.24	0.24	0.25	0.19	0.19	0.19	0.20	0.14	0.14	0.14	0.16
	Rate of Return on Equity											
R1: 3.0¢/kWh	0.00	0.02	0.74	1.14	0.00	0.00	0.48	0.95	0.00	0.00	0.02	0.74
R2: 5.25¢/kWh	0.70	0.70	0.74	1.14	0.40	0.40	0.48	0.95	0.00	0.00	0.02	0.74
R3: 7.5¢/kWh	1.11	1.11	1.11	1.14	0.89	0.89	0.89	0.95	0.65	0.65	0.65	0.74

Table 3-15. Economics of cogeneration - Oil Sands In-Situ

Figures 3-10 and 3-11 depict the IRR results from Table 3-15 graphically for the buy-deficit/sell-excess mode and the buy-all/sell-all mode respectively.

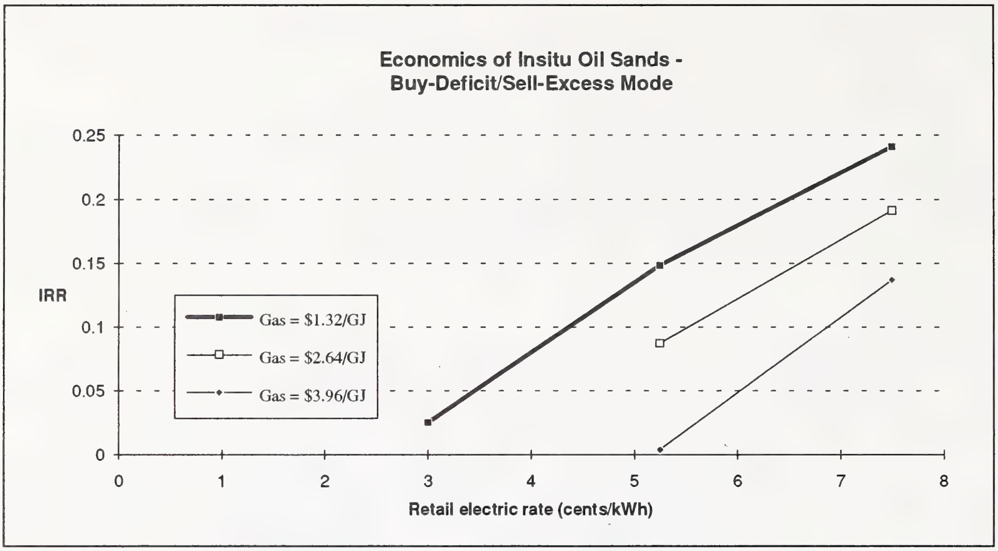

Figure 3-10. Economics - Buy-deficit/sell-excess mode - Oil Sands In-Situ

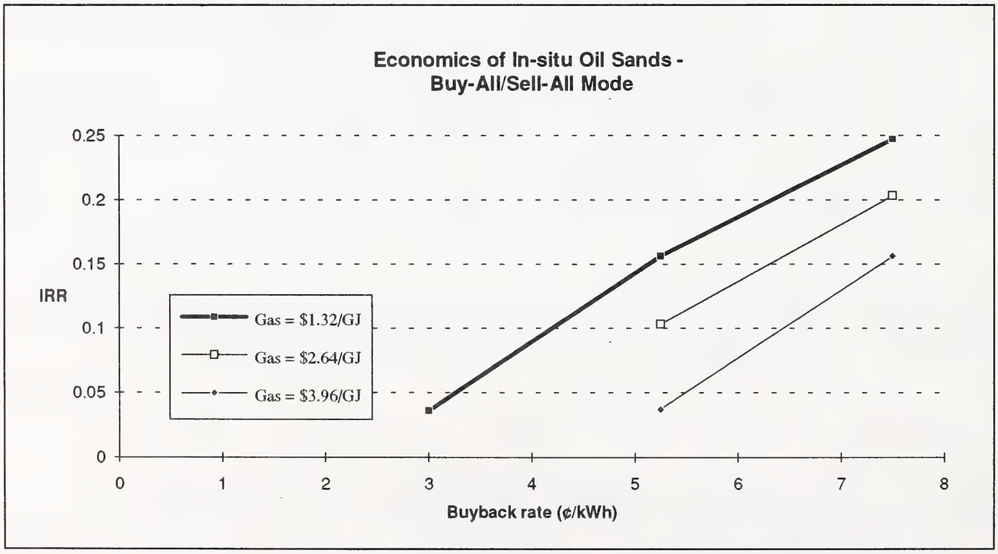

Figure 3-11. Economics - Buy-all/sell-all mode - Oil Sands In-Situ

Table 3-16 shows the levelized project cost for each of the two operating mode/sizing options, for two alternative lengths of financing term, and for each of the three levels of gas costs.

N. Gas ->	A:-$0.05/cu.m. ($1.32/GJ)		B:-$0.10/cu.m. ($2.64/GJ)		C:-$0.15/cu.m. ($3.96/GJ)	
Discount Rate: 7%	Levelized Cost (¢/kWh)					
Term: 15 yrs	3.50	**3.34**	4.75	**4.46**	6.00	**5.58**
Term: 20 yrs	3.25	**3.09**	4.50	**4.21**	5.75	**5.33**

Table 3-16. Levelized cost - Oil Sands In-Situ

The levelized cost of electricity ranges from 3 to 6¢/kWh depending on the cost of gas.

Analysis of Potential

Percent accepting is shown as a function of electric rate in Figure 3-12 for buy-deficit/sell-excess mode and as a function of buyback rate in Figure 3-13 for buy-all/sell-all mode. In both cases there is no economic potential at 3¢/kWh so no point is shown on the graphs for this rate level.

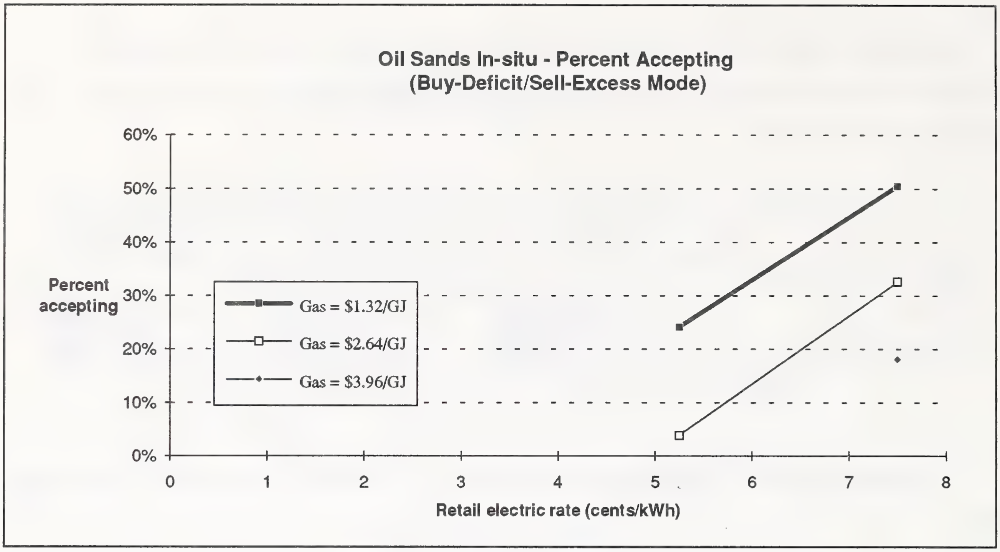

Figure 3-12. Percent accepting - Buy-deficit/sell-excess mode - Oil Sands In-Situ

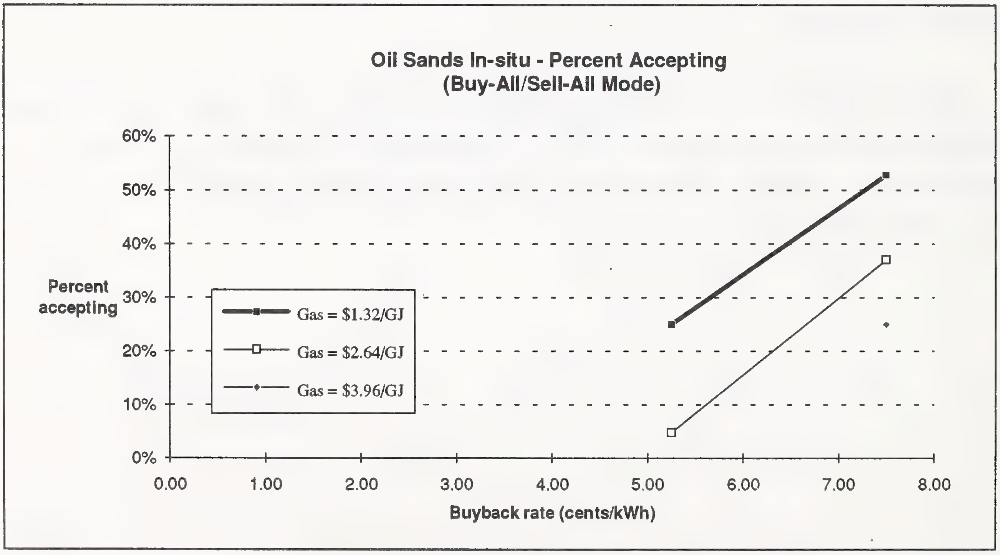

Figure 3-13. Percent accepting - Buy-all/sell-all mode - Oil Sands In-Situ

Table 3-17 summarizes the calculation of technical and economic potential for the 1992 and 2005 scenarios and provides a comparison to current implementation.

	1992		2005	
	Electric Peak	Thermal Peak	Electric Peak	Thermal Peak
Number of Facilities	5.8		15.8	
Representative Capacity (MW)	20.00	39.69	20.00	39.69
Technical Potential (MW)	116.00	230.20	316.00	627.10
Percent Accepting	0.0%	0.0%	0.0%	0.0%
Economic Potential (MW)	0.00	0.00	0.00	0.00
1990 Implementation (MW)	0			

Table 3-17. Base case summary - Oil Sands In-Situ

Discussion of Results

Under either buy-deficit/sell-excess mode or buy-all/sell-all mode, none of the technical potential is expected to be economic at the low (3.0¢/kWh) electric rates predicted. As with oil sands mining, this segment currently uses fuel gas rather than pipeline gas in its operations, and the price of this gas may be significantly lower than the price used in this analysis. The reasons for not using this lower gas price are the same as those identified earlier: the fuel gas is lower quality and may be subject to environmental constraints in the future, the Terms of Reference stated that gas was to be analyzed with royalties, and fuel gas costs were not available.

3.4 Oil Refineries and Upgraders

Oil refineries and upgraders are very similar in characteristics relevant to cogeneration potential. Thus, these two types of facilities are treated as a single segment in this analysis.

There are currently six major refinery facilities in production in Alberta as shown in Table 3-18 below.

Project	Crude Oil Production (bbls/day)[18]
Esso Petroleum Edmonton	164,875
Petro Canada Edmonton	121,140
Shell Canada Scotford	56,000
Turbo Resources Calgary	27,625
Husky Oil Lloydminster	23,315
Parkland Industries Bowden	6,700
TOTAL	399,655

Table 3-18. Production by major refineries[19]

There was approximately 6.9 MW of on-site capacity installed at these facilities as of 1990.[20] The ERCB predicts that use of conventional crude oil by Alberta refineries will increase slightly from its 1989 level of 454 PJ to 544 PJ by 2005.[21] Thus growth is not a major factor in the prospects for cogeneration in this part of the segment. Growth is expected to play an important role, however, in the prospects for cogeneration at upgrading facilities. Alberta currently has no stand-alone upgrading facilities. However, the Bi-Provincial Upgrader currently under construction in Lloydminster is scheduled to be completed in 1992 with a design capacity of 46,000

[18]Production in average barrels per day for first half of 1991.

[19]Electricity Policy Branch. Industry Consumer Profile, Alberta Department of Energy: Canada, March 1992.

[20]ERCB. 1991 Annual Electricity Statistics Report, Energy Resources Conservation Board: Calgary, 1991.

[21]ERCB. Energy Requirements in Alberta 1991-2005, p 53. Energy Resources Conservation Board: Calgary, 1991.

barrels/day of SCO. The ERCB predicts that an upgrader will phase in between 2001 and 2002 to produce 1.83 million m^3 of SCO per year.[22]

Representative facility characteristics

The representative oil refinery/upgrader processes 150,000 barrels per day. The average steam requirement of the representative facility is 383,000 lb/hr at a pressure of 550 psi and a temperature of 700 degrees F. The average annual electric demand at this facility is 40MW.[23]

The steam requirements of this facility can be met by a number of different technologies. Analyses were performed using gas turbine, steam turbine, and combined cycle technologies.

Results of COGENMASTER analysis

Of the three technologies evaluated, the gas turbine was the most economical because of its lower capital cost. The other two technologies had slightly longer paybacks. The results of the COGENMASTER analysis appear in Tables 3-19 through 3-21 below and are summarized in Appendix B.

Table 3-19 illustrates the systems considered for the two alternative operating modes.

Operating Mode	Cogeneration Sizing Strategy	System Type	Capacity (MW)
Buy All/Sell All	**Thermal Peak**	**Gas Turbine w/ Heat Recovery**	**79.07**
Buy Def./Sell Excess	Electric Peak	Gas Turbine w/ Heat Recovery	40.00

Table 3-19. System description - Oil Refineries and Upgraders

[22]ERCB. Energy Requirements in Alberta 1991-2005, pp 30-31. Energy Resources Conservation Board: Calgary, 1991.

[23]Procon International, Inc. Evaluation of Dual Energy Use Systems. Distillation Applications. Volume 3. Case Studies. Prepared for EPRI, EM-3868, pp3-46, February, 1985.

Scaling the representative facility up to the size of the segment requires 2.6 representative facilities in 1992 and 3.4 facilities in 2005. Assuming systems are sized to thermal peak, this gives 205 MW of technical potential in 1992 and 269 MW in 2005. Assuming sizing to electric peak, technical potential is 104 MW in 1992 and 136 MW in 2005.

The results of COGENMASTER runs measuring economic attractiveness of the proposed cogeneration investment are shown in terms of simple payback, internal rate of return, and rate of return on equity in Table 3-20 below. The shaded regions in this table indicate price scenarios for which the cogeneration plant is operated in the buy-all/sell-all mode.

N. Gas ->	**A:-$0.05/cu.m. ($1.32/GJ)**				**B:-$0.10/cu.m. ($2.64/GJ)**				**C:-$0.15/cu.m. ($3.96/GJ)**			
Buyback ¢/kWh->	1.00	3.00	5.25	7.50	1.00	3.00	5.25	7.50	1.00	3.00	5.25	7.50
Electric Rate	**Simple Payback (Years)**											
R1: 3.0¢/kWh	7.6	6.8	2.9	1.9	20.0	17.5	3.9	2.2	20.0	20.0	6.1	2.8
R2: 5.25¢/kWh	3.0	3.0	2.9	1.9	4.4	4.4	3.9	2.2	8.0	8.0	6.1	2.8
R3: 7.5¢/kWh	1.9	1.9	1.9	1.9	2.4	2.4	2.4	2.2	3.1	3.1	3.1	2.8
	Internal Rate of Return											
R1: 3.0¢/kWh	0.09	0.10	0.25	0.37	0.00	0.00	0.19	0.31	0.00	0.00	0.12	0.26
R2: 5.25¢/kWh	0.24	0.24	0.25	0.37	0.16	0.16	0.19	0.31	0.08	0.08	0.12	0.26
R3: 7.5¢/kWh	0.36	0.36	0.36	0.37	0.30	0.30	0.30	0.31	0.23	0.23	0.23	0.26
	Rate of Return on Equity											
R1: 3.0¢/kWh	0.40	0.47	1.13	1.68	0.00	0.00	0.87	1.43	0.00	0.00	0.56	1.19
R2: 5.25¢/kWh	1.09	1.09	1.13	1.68	0.78	0.78	0.87	1.43	0.36	0.36	0.56	1.19
R3: 7.5¢/kWh	1.64	1.64	1.64	1.68	1.36	1.36	1.36	1.43	1.07	1.07	1.07	1.19

Table 3-20. Economics of cogeneration - Oil Refineries and Upgraders

Figures 3-14 and 3-15 depict the IRR results from Table 3-20 graphically for the buy-deficit/sell-excess mode and the buy-all/sell-all mode respectively.

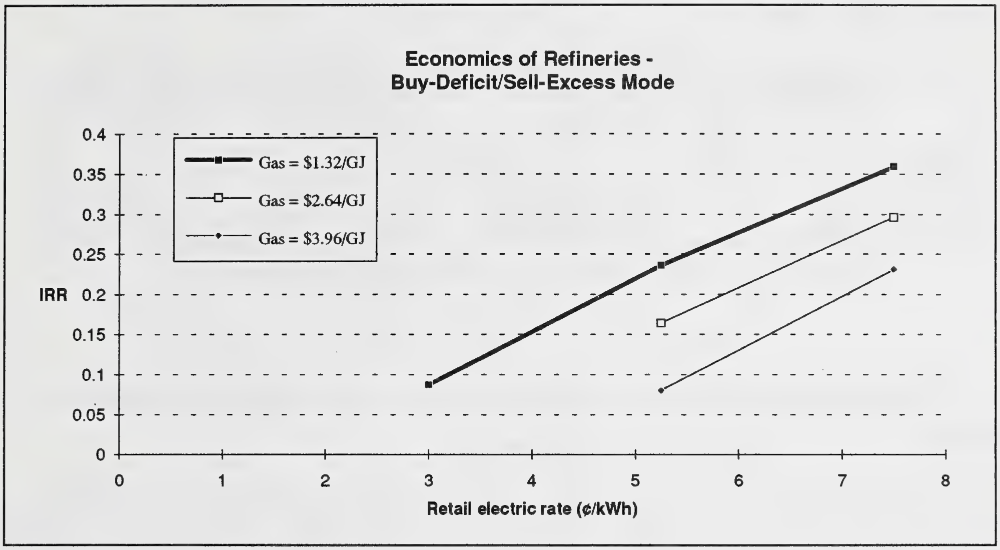

Figure 3-14. Economics - Buy-deficit/sell-excess mode - Oil Refineries and Upgraders

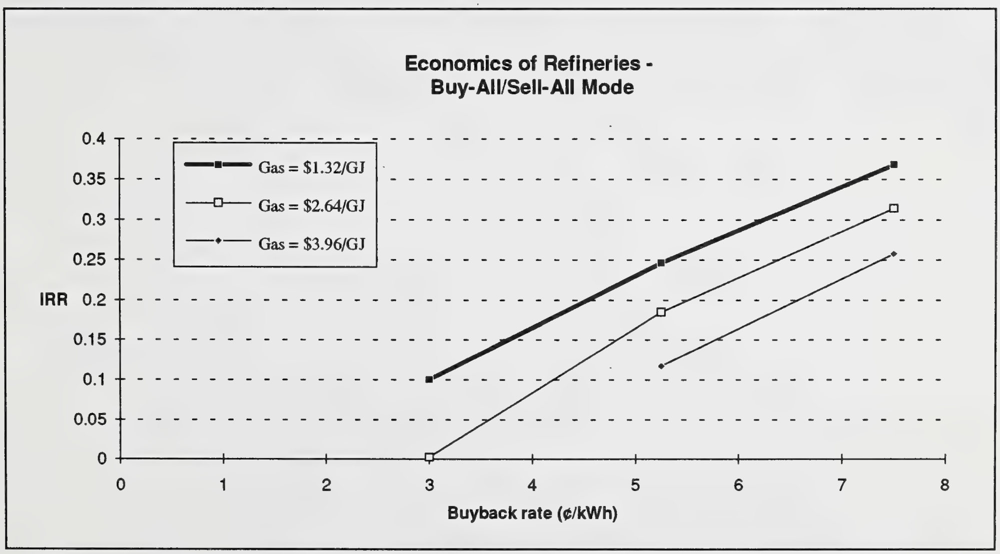

Figure 3-15. Economics - Buy-all/sell-all mode - Oil Refineries and Upgraders

Table 3-21 shows the levelized project cost for each of the two operating mode/sizing options, for two alternative lengths of financing term, and for each of the three levels of gas costs.

N. Gas ->	A:-$0.05/cu.m. ($1.32/GJ)		B:-$0.10/cu.m. ($2.64/GJ)		C:-$0.15/cu.m ($3.96/GJ)	
Discount Rate: 7%	Levelized Cost (¢/kWh)					
Term: 15 yrs	2.67	**2.50**	3.83	**3.52**	5.00	**4.54**
Term: 20 yrs	2.51	**2.34**	3.67	**3.35**	4.83	**4.37**

Table 3-21. Levelized cost - Oil Refineries and Upgraders

The levelized cost of electricity ranges from 2.3 to 5.0¢/kWh depending on the cost of gas.

Analysis of Potential

Percent accepting is shown as a function of electric rate in Figure 3-16 for buy-deficit/sell-excess mode and as a function of buyback rate in Figure 3-17 for buy-all/sell-all mode.

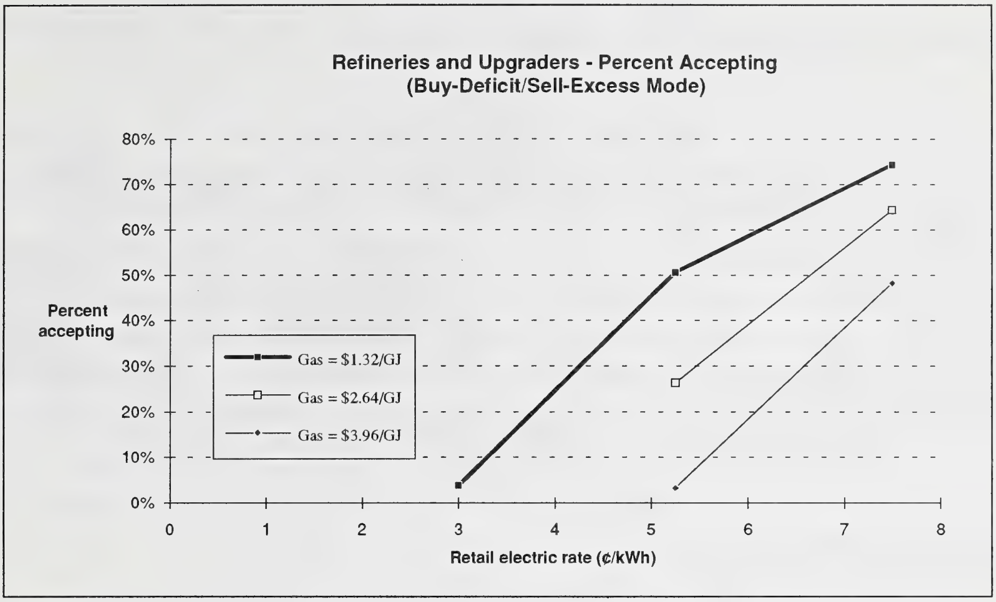

Figure 3-16. Percent accepting - Buy-deficit/sell-excess mode - Oil Refineries and Upgraders

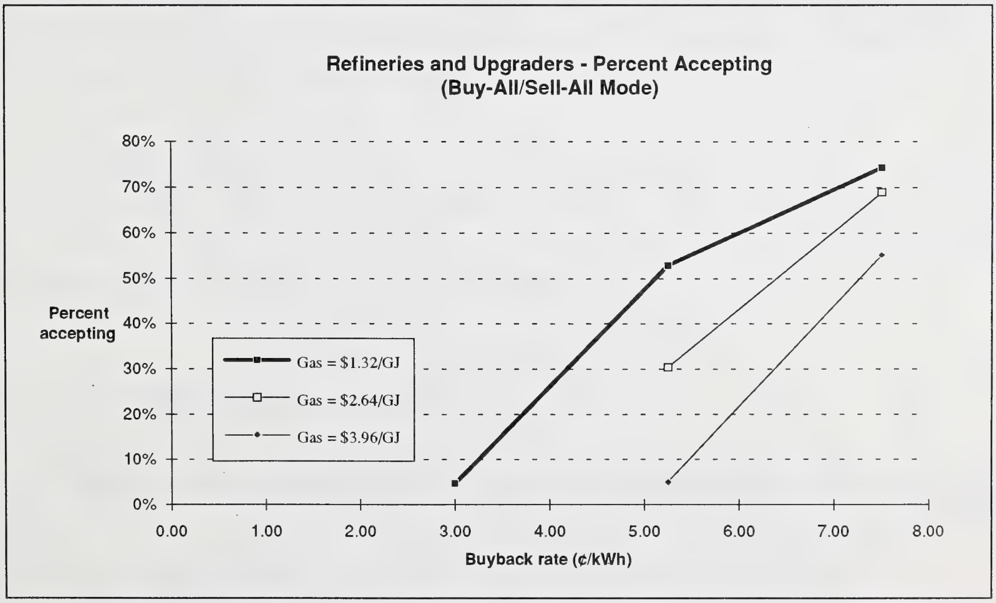

Figure 3-17. Percent accepting - Buy-all/sell-all mode - Oil Refineries and Upgraders

Table 3-22 summarizes the calculation of technical and economic potential for the 1992 and 2005 scenarios and provides a comparison to current implementation.

	1992		2005	
	Electric Peak	Thermal Peak	Electric Peak	Thermal Peak
Number of Facilities	2.6		3.4	
RepresentativeCapacity (MW)	40.00	79.07	40.00	79.07
Technical Potential (MW)	104.00	205.58	136.00	268.84
Percent Accepting	3.8%	4.7%	0.0%	0.0%
Economic Potential (MW)	3.97	9.62	0.00	0.00
1990 Implementation (MW)	6.9			

Table 3-22. Base case summary - Oil Refineries and Upgraders

Discussion of Results

Whether the system is operated in buy-all/sell-all mode or buy-deficit/sell-excess mode, only about 5% of technical potential is expected to be found economic at 1992 gas and electric rates. None of the technical potential appears economic at the higher gas price levels corresponding to the 2005 scenario.

3.5 Kraft Pulp Mills

There are 6 pulp mills currently operating in Alberta with one more (ALPAC) proposed to come on line. We include ALPAC in this analysis. Four of the pulp mills are Kraft pulp mills which will be treated in this section. The others are CTMP mills which are analyzed as sources of wood residue for waste generation in a separate section. CTMP mills are not analyzed for cogeneration potential because they do not have an adequate match between electric and thermal requirements. If CTMP mills were integrated with paper mills, it is possible that the integrated operation would present an opportunity for cogeneration. This possibility is not examined in this report. In 1990 there was 122 MW of installed generation in Kraft pulp mills in Alberta.[24] The ALPAC facility is proposed to add 95 MW of generation capacity (of which 15 MW is gas fired) for a total of 217 MW of capacity in this segment.

Representative Facility Characteristics

The representative Kraft pulp mill, produces newsprint and good quality paper and uses 17.3 GJ of steam and 1240 kWh of electricity per ton of output[25]. Using a pulp production rate of 300,000 ton per year, at a 100% load factor, the electric and thermal loads are 42 MW and 590 GJ/hr.

A wood fired steam turbine is the most appropriate technology for this segment. The cost of a boiler that uses wood as fuel will be more than for a boiler burning natural gas. A cost of $1,500/kW for the cogeneration system has been used in this analysis. No supplementary firing with natural gas is considered.

Results of COGENMASTER Analysis

Table 3-23 illustrates the systems considered for the two alternative operating modes.

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[24]ERCB. 1991 Annual Electricity Statistics Report, Energy Resources Conservation Board: Calgary, 1991.
[25]Marshall Sittig, Pulp and Paper Manufacture - Energy Conservation and Pollution Prevention, Published by Noyes Data Corporation, Park Ridge, NJ, USA, 1977.

Operating Mode	Cogeneration Sizing Strategy	System Type	Capacity (MW)
Buy All/Sell All	**Thermal Peak**	**Gas Turbine w/ Heat Recovery**	**149.72**
Buy Def./Sell Excess	Electric Peak	Gas Turbine w/ Heat Recovery	42.00

Table 3-23. System description - Kraft pulp mills

Scaling the representative facility up to the size of the segment (based on pulp production) requires 5 representative facilities in 1992 and 7 facilities in 2005. Thus total technical potential is 749 MW in 1992 and 1048 MW in 2005 assuming systems are sized to thermal peak. If systems are sized to electric peak, technical potential is 210 MW in 1992 and 294 MW in 2005. The analysis assumes that there is sufficient residue for these facilities to be sized to thermal peak.

The results of COGENMASTER runs measuring economic attractiveness of the proposed cogeneration investment are shown in terms of simple payback, internal rate of return, and rate of return on equity in Table 3-24 below.

Wood Cost->	**A:$-10/ODtonne**				**B:$0/ODtonne**				**C:$10/ODtonne**			
Buyback ¢/kWh->	1.00	3.00	5.25	7.50	1.00	3.00	5.25	7.50	1.00	3.00	5.25	7.50
Electric Rate	**Simple Payback (Years)**											
R1: 3.0¢/kWh	9.4	**8.9**	**4.1**	**2.7**	11.7	**10.8**	**4.5**	**2.8**	15.5	**13.6**	**4.9**	**3.0**
R2: 5.25¢/kWh	4.2	4.2	**4.1**	**2.7**	4.6	4.6	**4.5**	**2.8**	5.1	5.1	**4.9**	**3.0**
R3: 7.5¢/kWh	2.7	2.7	2.7	**2.7**	2.9	2.9	2.9	**2.8**	3.0	3.0	3.0	**3.0**
	Internal Rate of Return											
R1: 3.0¢/kWh	0.06	**0.07**	**0.18**	**0.27**	0.04	**0.05**	**0.16**	**0.25**	0.01	**0.02**	**0.15**	**0.24**
R2: 5.25¢/kWh	0.17	0.17	**0.18**	**0.27**	0.16	0.16	**0.16**	**0.25**	0.14	0.14	**0.15**	**0.24**
R3: 7.5¢/kWh	0.26	0.26	0.26	**0.27**	0.25	0.25	0.25	**0.25**	0.23	0.23	0.23	**0.24**
	Rate of Return on Equity											
R1: 3.0¢/kWh	0.20	**0.25**	**0.83**	**1.22**	0.02	**0.07**	**0.77**	**1.16**	0.00	**0.00**	**0.70**	**1.11**
R2: 5.25¢/kWh	0.81	0.81	**0.83**	**1.22**	0.74	0.4	**0.77**	**1.16**	0.67	0.67	**0.70**	**1.11**
R3: 7.5¢/kWh	1.20	1.20	1.20	**1.22**	1.14	1.14	1.14	**1.16**	1.08	1.08	1.08	**1.11**

Table 3-24 - Economics of cogeneration - Kraft pulp mills

Figures 3-18 and 3-19 depict the IRR results from Table 3-24 graphically.

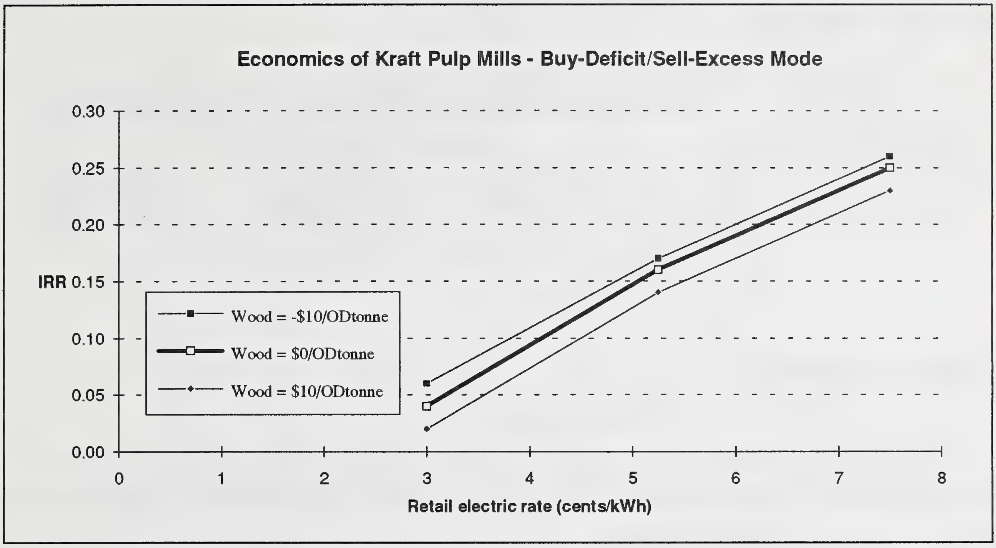

Figure 3-18. Economics - Buy-deficit/sell-excess mode - Kraft pulp mills

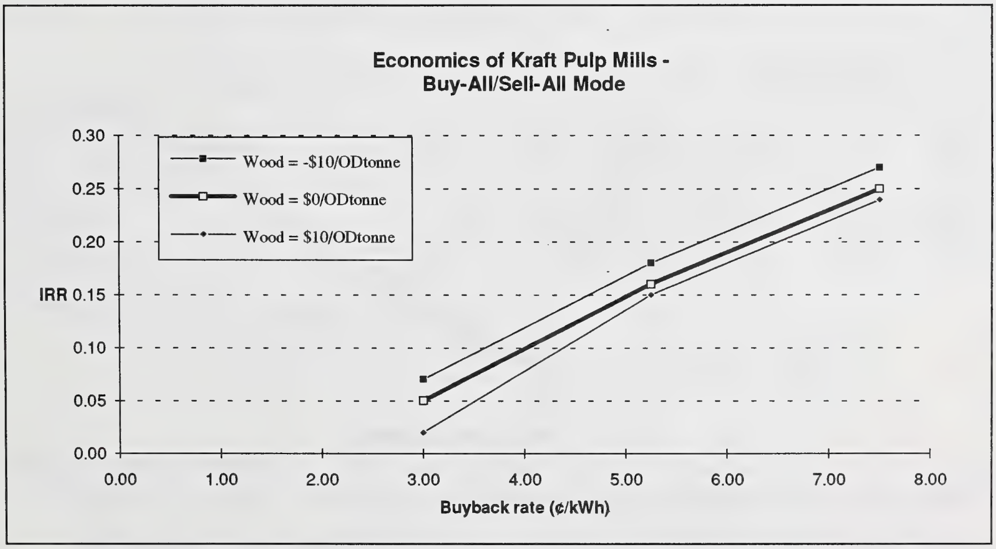

Figure 3-19. Economics - Buy-all/sell-all mode - Kraft pulp mills

Table 3-25 shows the levelized project cost for each of the two operating mode/sizing options, for two alternative lengths of financing term, and for each of the three levels of wood cost.

Wood ->	A:$-10/ODtonne		B:$0/ODtonne		C:$10/ODtonne	
Discount Rate: 7%	Levelized Cost (¢/kWh)					
Term: 15 yrs	2.93	2.84	3.29	3.17	3.65	3.50
Term: 20 yrs	2.68	2.60	3.04	2.93	3.41	3.25

Table 3-25. Levelized cost - Kraft pulp mills

Analysis of Potential

Percent accepting based on payback period is shown as a function of electric rate in Figure 3-20 for buy-deficit/sell-excess mode and as a function of buyback rate in Figure 3-21 for buy-all/sell-all mode.

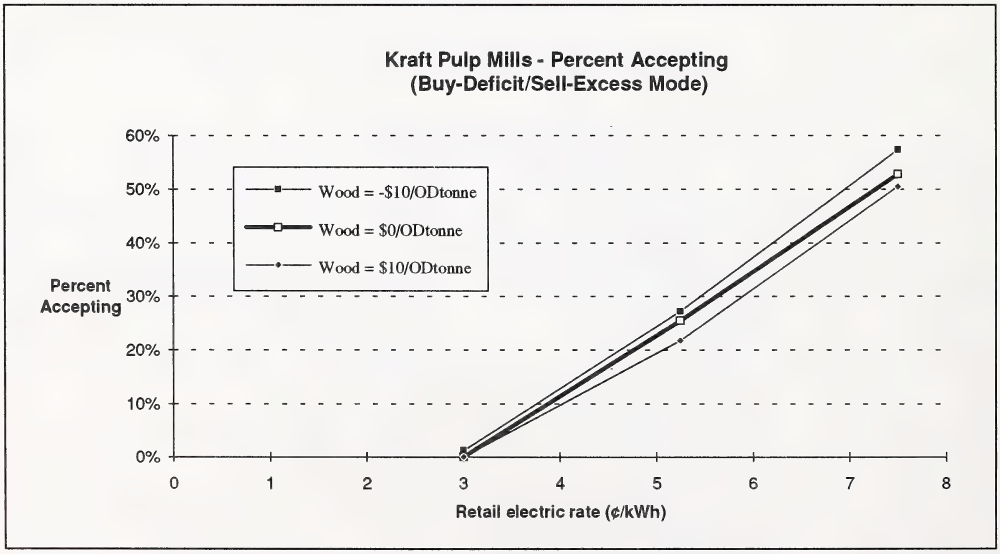

Figure 3-20. Percent accepting - Buy-deficit/sell-excess mode - Kraft pulp mills

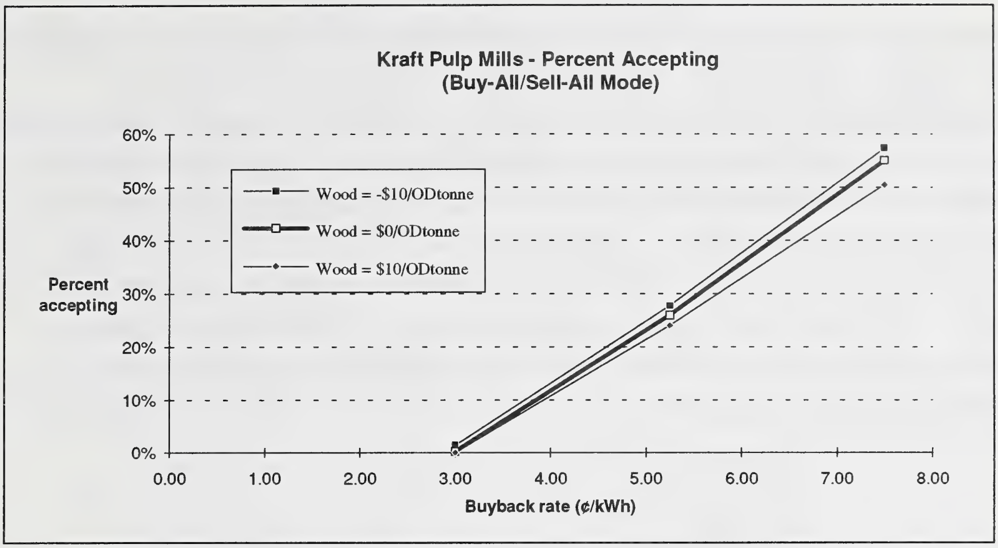

Figure 3-21. Percent accepting - Buy-all/sell-all mode - Kraft pulp mills

Table 3-26 summarizes the calculation of technical and economic potential for the 1992 and 2005 scenarios and provides a comparison to current implementation.

	1992		2005	
	Electric Peak	Thermal Peak	Electric Peak	Thermal Peak
Number of Facilities	5.0		7.0	
Representative Capacity (MW)	42.00	149.72	42.00	149.72
Technical Potential (MW)	210.00	748.60	294.00	1048.04
Percent Accepting	0.0%	0.2%	0.0%	0.2%
Economic Potential (MW)	0.00	1.50	0.00	1.50
Implementation (MW)	217*			

*Based on 1990 implementation of 122 MW plus 95 MW at ALPAC facility.

Table 3-26. Base case summary - Kraft pulp mills

Discussion of Results

Under either buy-deficit/sell-excess mode or buy-all/sell-all mode, less than 1% of technical potential is economically attractive at electric or buyback rates of 3¢/kWh. This result holds for both 1992 and 2005 scenarios. The present generation capacity in this segment greatly exceeds what our analysis shows would be economic to develop in 1992. There are several explanations for this. Some of the existing capacity in this

segment was developed in the 1970's and 1980's when electric prices were higher and were expected to rise rapidly. Another important motivation for installation of generating capacity in this segment was the need to dispose of waste. High alternative disposal costs may mean that the wood cost for this segment should be large and negative. A third motivation is that some facilities in this segment may not have had access to transmission lines or may have been concerned about the reliability of electric transmission to their remote locations. Finally, for cogeneration systems installed in the more recent plants, a major motivation may be that this is standard industry practice. As a result, the investment is not perceived as risky and lower expected returns can be justified.

3.6 Petrochemical and Chemical Plants

Alberta has a large and rapidly growing petrochemical and chemical industry. According to the ERCB, petrochemical plants are already the largest industrial consumer of natural gas and of energy resources in general in Alberta.[26] The ERCB predicts significant growth in the petrochemical industry as plant capacity is expected to rise from 5680 kT/year in 1990 to 13550 kT/year by 2002.[27]

Alberta's twelve largest (in kT production) petrochemical and chemical plants are shown in Table 3-27 below.

Company	Annual Production (kT)
Esso Chemical Redwater	3290
Dow Chemical Fort Saskatchewan	2130
Novacor Chemicals Joffre	1970
Sherritt Gordon Fort Saskatchewan	1820
Canadian Fertilizers Medicine Hat	1475
Celanese Canada Edmonton	984
Shell Canada Scotford	723
Novacor Chemicals Medicine Hat	720
Union Carbide Prentiss	366
Cominco/Alta Energy Joffre	350
I.C.I. Canada Caresland	225
B.F. Goodrich Fort Saskatchewan	110

Table 3-27. Production by major petrochemical and chemical plants[28]

Alberta's 19 largest electric consumers in this segment consume over 4 million MWh of electricity annually, of which almost 1.4 million MWh is generated on-site. The 21 largest gas consumers in the petrochemical segment consume over 145 million GJ annually, of which about 21 million GJ is used for cogeneration.

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[26]ERCB. Energy Requirements in Alberta 1991-2005, p 32. Energy Resources Conservation Board: Calgary, 1991.
[27]ERCB. Energy Requirements in Alberta 1991-2005, pp 55-58. Energy Resources Conservation Board: Calgary, 1991.
[28]Electricity Policy Branch. Industry Consumer Profile, Alberta Department of Energy: Canada, March 1992.

There is a significant technical potential for cogeneration in the petrochemical segment because of its high thermal needs. An analysis of production processes reveals that production of certain chemicals (e.g., chloralkali) is electric-intensive, while production of other chemicals (e.g., ethylene) requires large amounts of thermal energy. This does not rule out cogeneration, however, as both products may be made by a single company at the same location. This analysis has been based on the average electric/gas requirements of the large customers, assuming that the thermal to electric balance at the typical facility is roughly equivalent to that for the industry as a whole. This segment is very diverse, and it is likely that some facilities will have more potential than our representative facility, while others will have less potential. However, the representative facility is assumed to be a good indicator of the average level of potential in the segment.

Representative Facility Characteristics

Based on the consumption data in the consumer profile, the average annual electric and gas consumption for the large customers are 214,757 MWh and 5,443,219 GJ respectively. These consumption figures have been derived based on power and gas purchases of the large customers, and adjusted for any on-site generation. In 1990, there was 207.6 MW of on-site capacity at petrochemical plants in Alberta.[29]

The normal load profiles for the representative facility have been taken from a California Energy Commission study on cogeneration and small power.[30] The average consumption of the large customers was then applied to this normal load profile. The study also states that 77 percent of the thermal load in this segment can be displaced by a cogeneration system.

The cogeneration system configuration and technologies will vary based on the type of thermal output required at the plant. However, all three technologies -- gas

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[29]ERCB. 1991 Annual Electricity Statistics Report, Energy Resources Conservation Board: Calgary, 1991.

[30]Regional Economic Research Inc., Forecasts of annual capacities of the supply of electricity likely to be available (LTBA) from qualifying facilities not subject to CEC jurisdiction, prepared for the California Energy Commission, February 1988.

turbines, steam turbines, and combined cycle plants -- should generally be applicable in this segment. An analysis was conducted using each of these three technologies.

Results of COGENMASTER Analysis

Of the three technologies evaluated, the gas turbine was the most economical because of its lower capital cost. The other two technologies had slightly longer paybacks. The results of the COGENMASTER analysis appear in Tables 3-28 through 3-30 below and are summarized in Appendix B.

Table 3-28 illustrates the systems considered for the two alternative operating modes.

Operating Mode	Cogeneration Sizing Strategy	System Type	Capacity (MW)
Buy All/Sell All	**Thermal Peak**	**Gas Turbine w/ Heat Recovery**	**73.33**
Buy Def./Sell Excess	Electric Peak	Gas Turbine w/ Heat Recovery	27.88

Table 3-28. System description - Petrochemical and chemical plants

Scaling the representative facility up to the size of the segment requires 19 representative facilities in 1992 and 49 facilities in 2005. If systems are sized to thermal peak, total technical potential is 1393 MW in 1992 and 3593 MW in 2005. If sizing is to electric peak, technical potential is 530 MW in 1992 and 1366 MW in 2005.

The results of COGENMASTER runs measuring economic attractiveness of the proposed cogeneration investment are shown in terms of simple payback, internal rate of return, and rate of return on equity in Table 3-28 below. The shaded regions in this table indicate price scenarios for which the cogeneration plant is operated in the buy-all/sell-all mode.

N. Gas ->	A:-$0.05/cu.m. ($1.32/GJ)				B:-$0.10/cu.m. ($2.64/GJ)				C:-$0.15/cu.m. ($3.96/GJ)			
Buyback ¢/kWh->	1.00	3.00	5.25	7.50	1.00	3.00	5.25	7.50	1.00	3.00	5.25	7.50
Electric Rate	Simple Payback (Years)											
R1: 3.0¢/kWh	9.2	7.5	3.0	1.9	20.0	20.0	4.4	2.3	20.0	20.0	7.8	3.1
R2: 5.25¢/kWh	3.5	3.3	3.0	1.9	5.6	5.0	4.4	2.3	12.9	10.1	7.8	3.1
R3: 7.5¢/kWh	2.2	2.1	2.0	1.9	2.8	2.7	2.5	2.3	4.0	3.7	3.4	3.1
	Internal Rate of Return											
R1: 3.0¢/kWh	0.06	0.09	0.24	0.36	0.00	0.00	0.17	0.30	0.00	0.00	0.08	0.23
R2: 5.25¢/kWh	0.20	0.22	0.24	0.36	0.13	0.15	0.17	0.30	0.03	0.05	0.08	0.23
R3: 7.5¢/kWh	0.32	0.33	0.34	0.36	0.25	0.27	0.28	0.30	0.18	0.20	0.21	0.23
	Rate of Return on Equity											
R1: 3.0¢/kWh	0.23	0.41	1.10	1.64	0.00	0.00	0.79	1.37	0.00	0.00	0.37	1.08
R2: 5.25¢/kWh	0.95	1.01	1.10	1.64	0.61	0.69	0.79	1.37	0.00	0.12	0.37	1.08
R3: 7.5¢/kWh	1.44	1.50	1.57	1.64	1.16	1.22	1.29	1.37	0.86	0.92	0.99	1.08

Table 3-29. Economics of cogeneration - Petrochemical and chemical plants

Figures 3-22 and 3-23 depict the IRR results from Table 3-29 graphically for the buy-deficit/sell-excess mode and the buy-all/sell-all mode respectively.

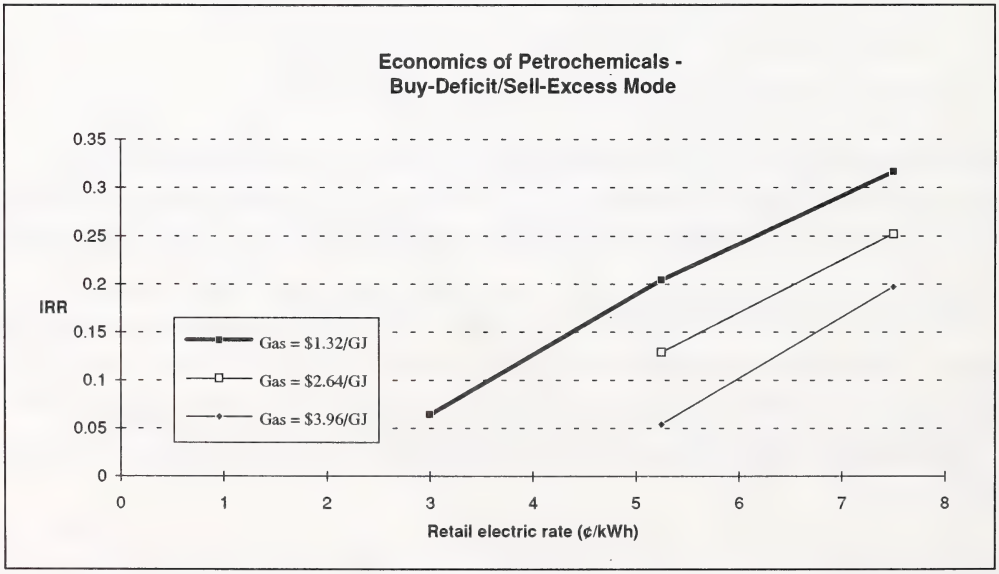

Figure 3-22. Economics - Buy-deficit/sell-excess mode - Petrochemical and chemical plants

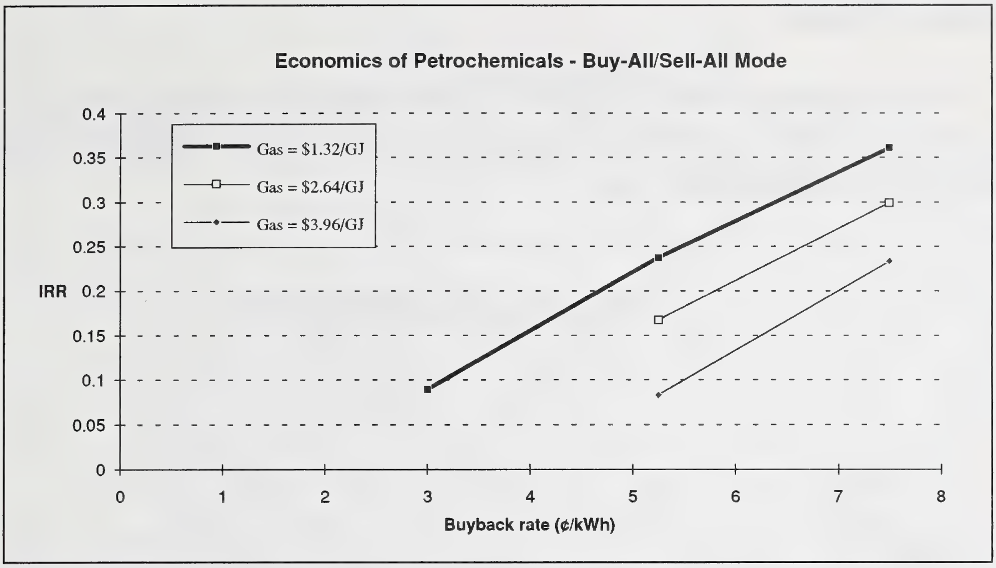

Figure 3-23. Economics - Buy-all/sell-all mode - Petrochemical and chemical plants

Table 3-30 shows the levelized project cost for each of the two operating mode/sizing options, for two alternative lengths of financing term, and for each of the three levels of gas costs.

N. Gas ->	A:-$0.05/cu.m. ($1.32/GJ)		B:-$0.10/cu.m. ($2.64/GJ)		C:-$0.15/cu.m ($3.96/GJ)	
Discount Rate: 7%	Levelized Cost (¢/kWh)					
Term: 15 yrs	2.69	**2.64**	3.86	**3.81**	5.02	**4.97**
Term: 20 yrs	2.53	**2.48**	3.69	**3.64**	4.86	**4.80**

Table 3-30. Levelized cost - Petrochemical and chemical plants

The levelized cost of electricity ranges from 2.5 to 5¢/kWh depending on the cost of gas.

Economic Potential

Percent accepting based on payback period is shown as a function of electric rate in Figure 3-24 for buy-deficit/sell-excess mode and as a function of buyback rate in Figure 3-25 for buy-all/sell-all mode.

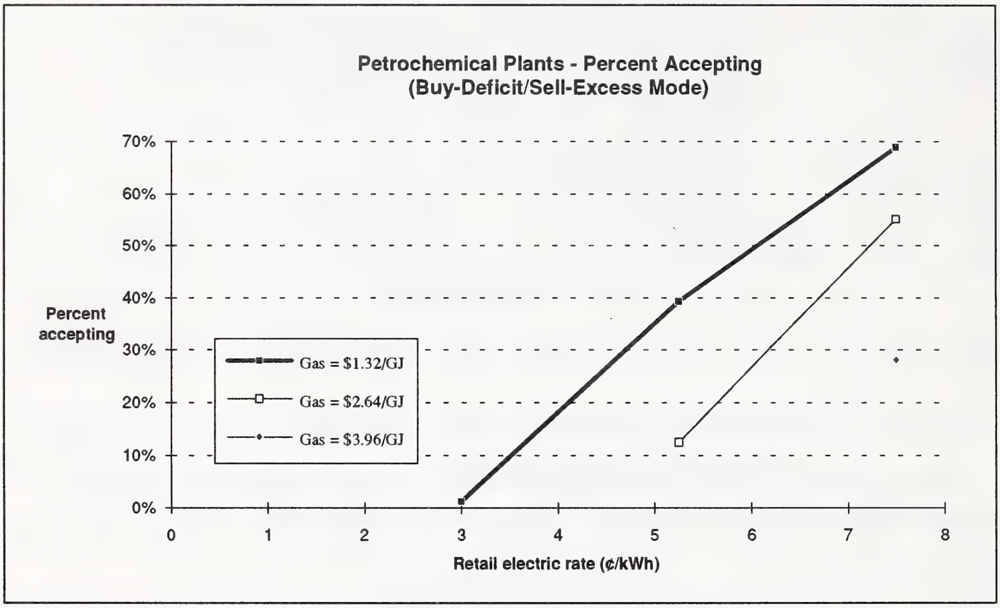

Figure 3-24. Percent accepting - Buy-deficit/sell-excess mode - Petrochemical and chemical plants

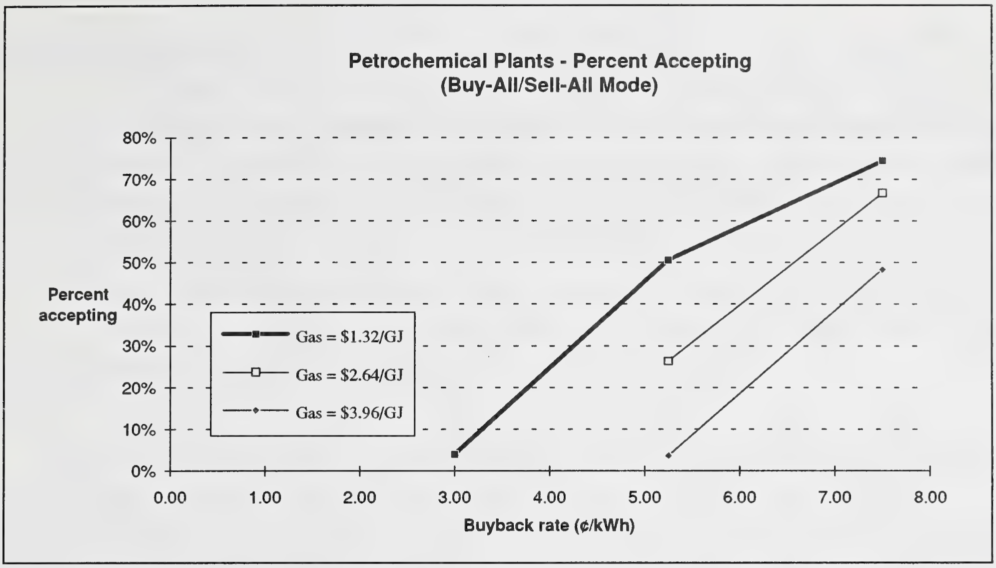

Figure 3-25. Percent accepting - Buy-all/sell-all mode - Petrochemical and chemical plants

Table 3-31 summarizes the calculation of technical and economic potential for the 1992 and 2005 scenarios and provides a comparison to current implementation.

	1992		2005	
	Electric Peak	Thermal Peak	Electric Peak	Thermal Peak
Number of Facilities	19		49	
Representative Capacity (MW)	27.88	73.33	27.88	73.33
Technical Potential (MW)	529.72	1393.27	1366.12	3593.17
Percent Accepting	1.2%	4.0%	0.0%	0.0%
Economic Potential (MW)	6.36	55.00	0.00	0.00
1990 Implementation (MW)	208			

Table 3-31. Base case summary - Petrochemical and chemical plants

Discussion of Results

Under either buy-deficit/sell-excess or buy-all/sell-all mode operation, less than 5% of technical potential will be perceived as economically attractive at 1992 gas and electric rates. At the higher 2005 gas rates, no economic potential is predicted for

3.0¢/kWh electric rates. Current implementation of cogeneration is much higher than the economic potential in either of these scenarios. There are two possible explanations for this discrepancy. The first is that some motivations for installing generation in this segment are not adequately captured in the model. The second is that the generation that is installed is at facilities whose characteristics are much more favorable to cogeneration than those of the “average” representative facility. A sensitivity analysis on variation of payback period within segments addresses this problem and is found in the section on Sensitivity to Risk and Other Factors.

3.7 Large Educational

For this analysis, the large education segment includes a total of 10 educational campuses in the province. There are 10 campuses in Alberta with an electric demand of over 2 MW[31]. In 1990, there was 4.8 MW of on-site capacity installed at large educational institutions.[32]

Representative Facility Characteristics

The average customer in this segment consumes 48,871 MWh and 268,406 GJ annually[33]. The average facility has been used as the representative facility for this segment. The electric and gas profiles for the facility have been taken from the default data base in the COGENMASTER model, and modified using the annual consumptions from the consumer profile.

The most applicable technology for this segment is the gas engine, although small gas turbines can also be used in the larger educational campuses. The analysis has been performed using the gas engine cogeneration system. The total cogeneration system capacity may exceed a few megawatts in some cases. In such cases, multiple gas engines are assumed to be installed to increase the overall system reliability.

Results of COGENMASTER Analysis

The results of the COGENMASTER analysis appear in Tables 3-32 through 3-34 below and are summarized in Appendix B.

Table 3-32 illustrates the systems considered for the two alternative operating modes.

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[31] Electricity Policy Branch. Industry Consumer Profile, Alberta Department of Energy: Canada, March 1992.
[32] ERCB. 1991 Annual Electricity Statistics Report, Energy Resources Conservation Board: Calgary, 1991.
[33] Electricity Policy Branch. Industry Consumer Profile, Alberta Department of Energy: Canada, March 1992.

Operating Mode	Cogeneration Sizing Strategy	System Type	Capacity (MW)
Buy All/Sell All	**Thermal Peak**	**Gas Engine w/ Heat Recovery**	**5.70**
Buy Def./Sell Excess	Electric Peak	Gas Engine w/ Heat Recovery	2.86

Table 3-32. System description - Large educational

The number of large educational campuses is expected to grow from 10 in 1992 to 11 by 2005. Assuming systems implemented are sized to thermal peak, this implies technical potential of 57 MW in 1992 and 63 MW in 2005. If systems are sized to electric peak, technical potential is 29 MW in 1992 and 31 MW in 2005.

The results of COGENMASTER runs measuring economic attractiveness of the proposed cogeneration investment are shown in terms of simple payback, internal rate of return, and rate of return on equity in Table 3-33 below. The shaded regions in this table indicate price scenarios for which the cogeneration plant is operated in the buy-all/sell-all mode.

N. Gas ->	**A:-$0.05/cu.m. ($1.32/GJ)**				**B:-$0.10/cu.m. ($2.64/GJ)**				**C:-$0.15/cu.m. ($3.96/GJ)**			
Buyback ¢/kWh->	1.00	3.00	5.25	7.50	1.00	3.00	5.25	7.50	1.00	3.00	5.25	7.50
Electric Rate	**Simple Payback (Years)**											
R1: 3.0¢/kWh	20.0	**20.0**	**10.2**	**5.1**	20.0	**20.0**	**18.8**	**6.6**	20.0	**20.0**	**20.0**	**9.3**
R2: 5.25¢/kWh	9.6	9.6	**9.6**	**5.1**	15.2	15.2	**15.2**	**6.6**	20.0	20.0	**20.0**	**9.3**
R3: 7.5¢/kWh	4.9	4.9	4.9	**4.9**	6.1	6.1	6.1	**6.1**	7.9	7.9	7.9	**7.9**
	Internal Rate of Return											
R1: 3.0¢/kWh	0.00	**0.00**	**0.05**	**0.14**	0.00	**0.00**	**0.00**	**0.10**	0.00	**0.00**	**0.00**	**0.06**
R2: 5.25¢/kWh	0.06	0.06	**0.06**	**0.14**	0.01	0.01	**0.01**	**0.10**	0.00	0.00	**0.00**	**0.06**
R3: 7.5¢/kWh	0.15	0.15	0.15	**0.15**	0.12	0.12	0.12	**0.12**	0.08	0.08	0.08	**0.08**
	Rate of Return on Equity											
R1: 3.0¢/kWh	0.00	**0.00**	**0.06**	**0.25**	0.00	**0.00**	**0.00**	**0.16**	0.00	**0.00**	**0.00**	**0.08**
R2: 5.25¢/kWh	0.07	0.07	**0.07**	**0.25**	0.00	0.00	**0.00**	**0.16**	0.00	0.00	**0.00**	**0.08**
R3: 7.5¢/kWh	0.26	0.26	0.26	**0.26**	0.18	0.18	0.18	**0.18**	0.11	0.11	0.11	**0.11**

Table 3-33. Economics of cogeneration - Large educational

Figures 3-26 and 3-27 depict the IRR results from Table 3-33 graphically for the buy-deficit/sell-excess mode and the buy-all/sell-all mode respectively.

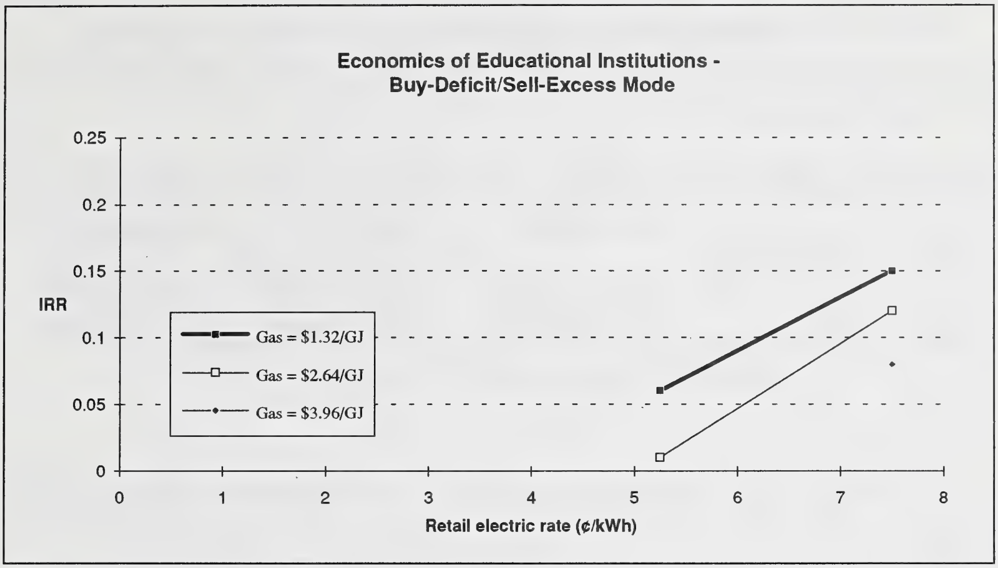

Figure 3-26. Economics - Buy-deficit/sell-excess mode - Large educational

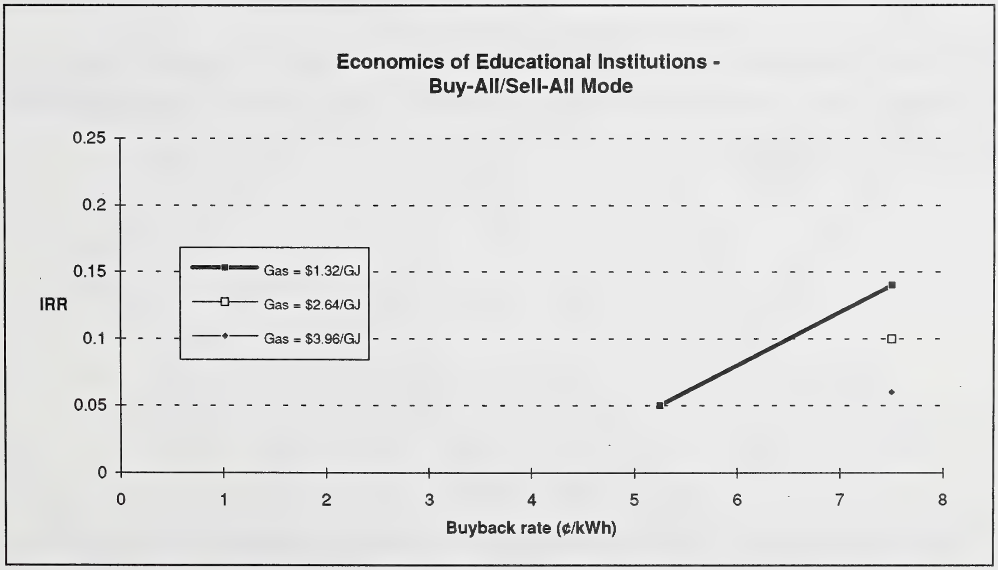

Figure 3-27. Economics - Buy-all/sell-all mode - Large educational

Table 3-34 shows the levelized project cost for each of the two operating mode/sizing options, for two alternative lengths of financing term, and for each of the three levels of gas costs.

N. Gas ->	**A:-$0.05/cu.m. ($1.32/GJ)**		**B:-$0.10/cu.m. ($2.64/GJ)**		**C:-$0.15/cu.m ($3.96/GJ)**	
Discount Rate: 7%	Levelized Cost (¢/kWh)					
Term: 15 yrs	5.22	**5.36**	6.09	**6.38**	6.99	**7.39**
Term: 20 yrs	4.89	**5.03**	5.76	**6.05**	6.48	**7.07**

Table 3-34. Levelized cost - Large educational

The levelized cost of electricity ranges from 4.9 to 7.4¢/kWh depending on the cost of gas.

Analysis of Potential

Percent accepting based on payback period is shown as a function of electric rate in Figure 3-28 for buy-deficit/sell-excess mode and as a function of buyback rate in Figure 3-29 for buy-all/sell-all mode.

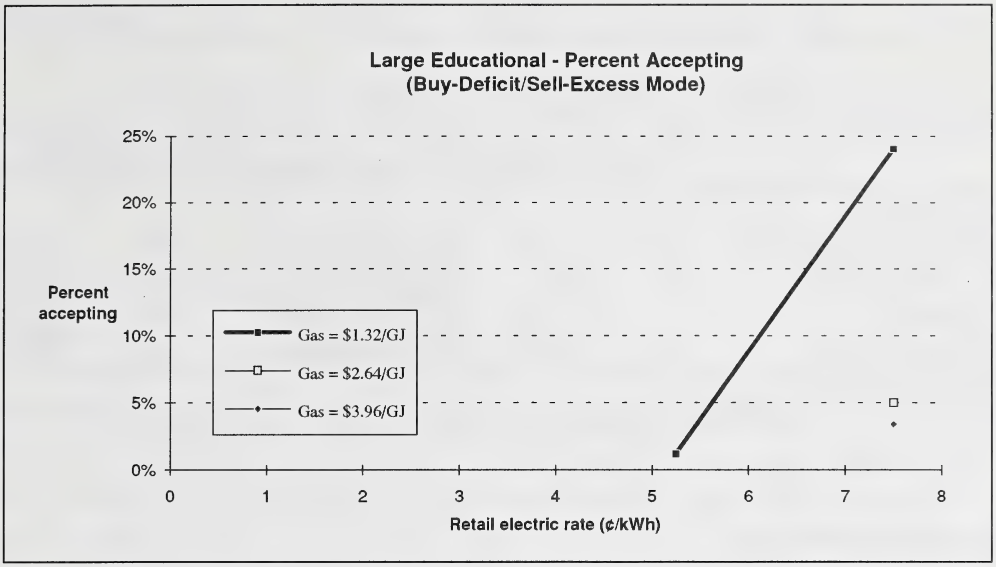

Figure 3-28. Percent accepting - Buy-deficit/sell-excess mode - Large educational

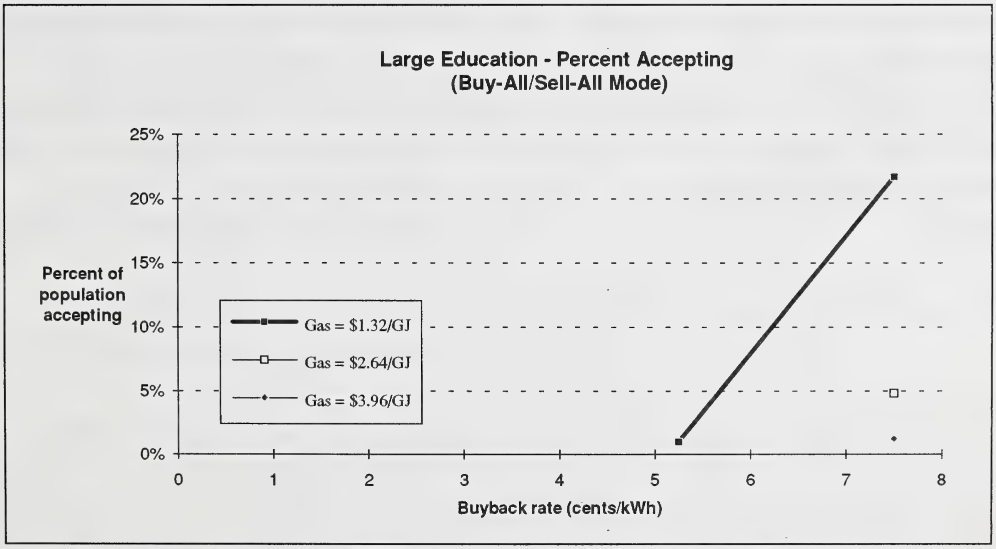

Figure 3-29. Percent accepting - Buy-all/sell-all mode - Large educational

Table 3-35 summarizes the calculation of technical and economic potential for the 1992 and 2005 scenarios and provides a comparison to current implementation.

	1992		2005	
	Electric Peak	Thermal Peak	Electric Peak	Thermal Peak
Number of Facilities	10		11	
Representative Capacity (MW)	2.86	5.70	2.86	5.70
Technical Potential (MW)	28.60	57.00	31.46	62.70
Percent Accepting	1.2%	1.0%	0.0%	0.0%
Economic Potential (MW)	0.34	0.55	0.00	0.00
1990 Implementation (MW)	4.8			

Table 3-35. Base case summary - Large educational

Discussion of Results

Our analysis shows the potential for cogeneration in this segment to be very small. Under either mode of operation, less than 2% of technical potential will eventually be implemented at electric rates of 5.25¢/kwh and 1992 gas price levels. No economic potential is evident at the higher 2005 gas rates. Currently 4.8MW of capacity are installed at large educational facilities in Alberta. This amount of current cogeneration may be due to the fact that public sector financing provides a universally low cost of capital to this segment. It may also represent power that is required for backup.

3.8 Hospitals

This analysis is based on Alberta's 13 large hospitals. The number of electric customers having a demand of over 2 MW is 13[34]. As of 1990, there was 22.9 MW of on-site generation installed at hospitals in Alberta.[35]

Representative Facility Characteristics

The average large hospital consumes 22,791 MWh and 174,551 GJ annually[36]. The average facility has been used as the representative facility for this segment. The electric and gas profiles for the facility have been taken from the default data base in the COGENMASTER model and modified using the annual consumptions from the consumer profile.

The most applicable technology for this segment is the gas engine. Small gas turbines can also be used in the larger hospitals. The analysis has been performed using the gas engine cogeneration system. The total cogeneration system capacity may exceed a few megawatts in some cases. In such cases, multiple gas engines are assumed to be installed to increase the overall system reliability.

Results of COGENMASTER Analysis

The results of the COGENMASTER analysis appear in Tables 3-36 through 3-38 below and are summarized in Appendix B.

Table 3-36 illustrates the systems considered for the two alternative operating modes.

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[34]Electricity Policy Branch. Industry Consumer Profile, Alberta Department of Energy: Canada, March 1992.

[35]ERCB. 1991 Annual Electricity Statistics Report, Energy Resources Conservation Board: Calgary, 1991.

[36]Electricity Policy Branch. Industry Consumer Profile, Alberta Department of Energy: Canada, March 1992.

Operating Mode	Cogeneration Sizing Strategy	System Type	Capacity (MW)
Buy All/Sell All	**Thermal Peak**	**Gas Engine w/ Heat Recovery**	**6.59**
Buy Def./Sell Excess	Electric Peak	Gas Engine w/ Heat Recovery	1.33

Table 3-36. System description - Hospitals

The number of large hospitals is predicted to grow from 13 in 1992 to 18 in 2005.[37] If systems are sized to peak thermal load, technical potential is 86 MW in 1992 and 119 MW in 2005. If sizing is to electric peak, technical potential is 17 MW in 1992 and 24 MW in 2005.

The results of COGENMASTER runs measuring economic attractiveness of the proposed cogeneration investment are shown in terms of simple payback, internal rate of return, and rate of return on equity in Table 3-37 below. The shaded regions in this table indicate price scenarios for which the cogeneration plant is operated in the buy-all/sell-all mode.

N. Gas ->	**A:-\$0.05/cu.m. (\$1.32/GJ)**				**B:-\$0.10/cu.m. (\$2.64/GJ)**				**C:-\$0.15/cu.m. (\$3.96/GJ)**			
Buyback ¢/kWh->	1.00	3.00	5.25	7.50	1.00	3.00	5.25	7.50	1.00	3.00	5.25	7.50
Electric Rate	**Simple Payback (Years)**											
R1: 3.0¢/kWh	20.0	**20.0**	**10.7**	**5.2**	20.0	**20.0**	**20.0**	**7.0**	20.0	**20.0**	**20.0**	**10.6**
R2: 5.25¢/kWh	9.3	9.3	**9.3**	**5.2**	13.6	13.6	**13.6**	**7.0**	20.0	20.0	**20.0**	**10.6**
R3: 7.5¢/kWh	4.8	4.8	4.8	**4.8**	5.8	5.8	5.8	**5.8**	7.3	7.3	7.3	**7.3**
	Internal Rate of Return											
R1: 3.0¢/kWh	0.00	**0.00**	**0.05**	**0.14**	0.00	**0.00**	**0.00**	**0.10**	0.00	**0.00**	**0.00**	**0.05**
R2: 5.25¢/kWh	0.06	0.06	**0.06**	**0.14**	0.02	0.02	**0.02**	**0.10**	0.00	0.00	**0.00**	**0.05**
R3: 7.5¢/kWh	0.15	0.15	0.15	**0.15**	0.12	0.12	0.12	**0.12**	0.09	0.09	0.09	**0.09**
	Rate of Return on Equity											
R1: 3.0¢/kWh	0.00	**0.00**	**0.05**	**0.24**	0.00	**0.00**	**0.00**	**0.14**	0.00	**0.00**	**0.00**	**0.05**
R2: 5.25¢/kWh	0.08	0.08	**0.08**	**0.24**	0.01	0.01	**0.01**	**0.14**	0.00	0.00	**0.00**	**0.05**
R3: 7.5¢/kWh	0.27	0.27	0.27	**0.27**	0.20	0.20	0.20	**0.20**	0.13	0.13	0.13	**0.13**

Table 3-37. Economics of cogeneration - Hospitals

[37]Based on energy consumption projections. Energy Efficiency Branch. A Discussion Paper on the Potential for Reducing Carbon Dioxide Emissions in Alberta: 1988-2005, Alberta Department of Energy: Canada, January 1991.

Figures 3-30 and 3-31 depict the IRR results from Table 3-37 graphically for the buy-deficit/sell-excess mode and the buy-all/sell-all mode respectively.

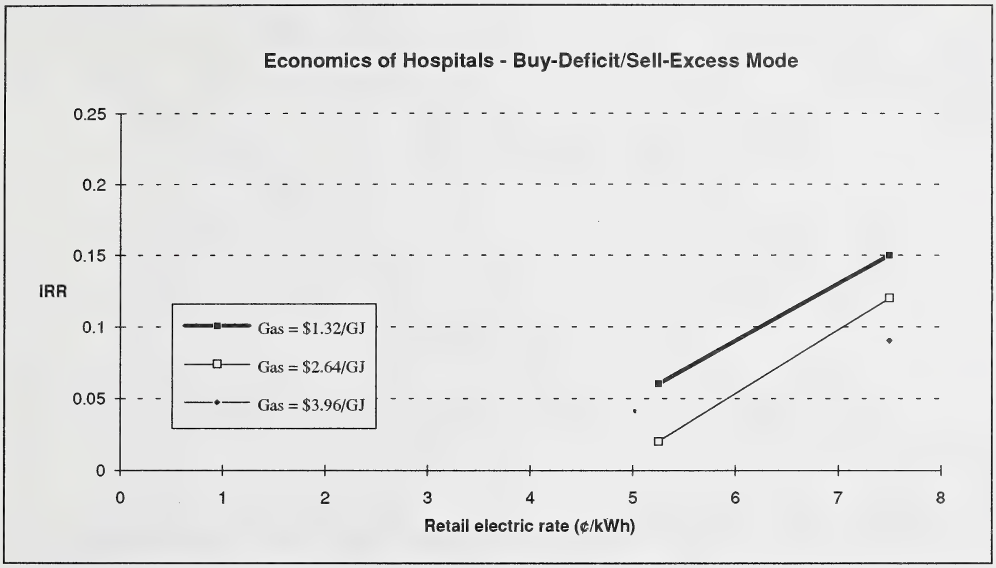

Figure 3-30. Economics - Buy-deficit/sell-excess mode - Hospitals

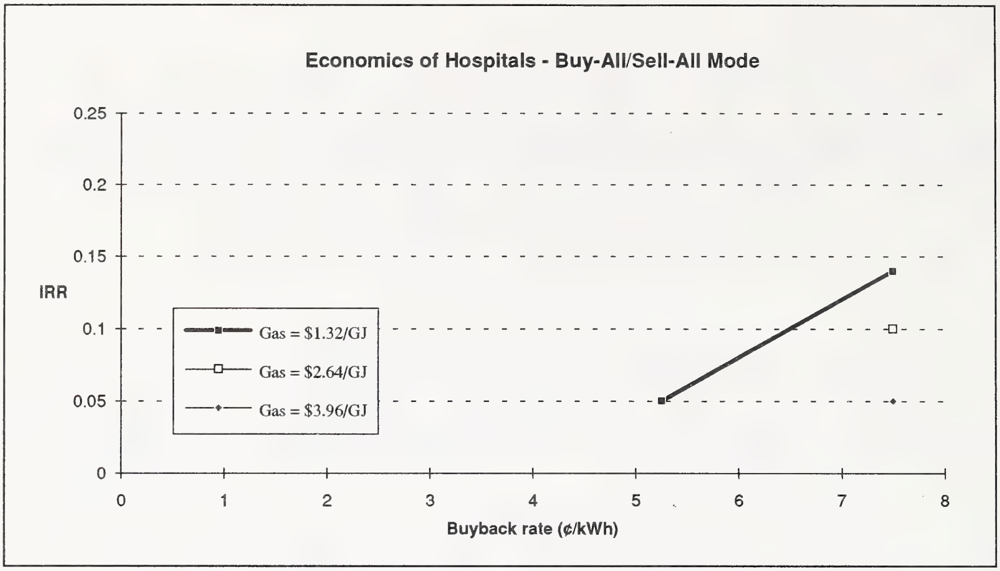

Figure 3-31. Economics - Buy-all/sell-all mode - Hospitals

Table 3-38 shows the levelized project cost for each of the two operating mode/sizing options, for two alternative lengths of financing term, and for each of the three levels of gas costs.

N. Gas ->	A:-$0.05/cu.m. ($1.32/GJ)		B:-$0.10/cu.m. ($2.64/GJ)		C:-$0.15/cu.m. ($3.96/GJ)	
Discount Rate: 7%	Levelized Cost (¢/kWh)					
Term: 15 yrs	5.13	5.46	5.91	6.58	6.79	7.70
Term: 20 yrs	4.80	5.13	5.58	6.25	6.33	7.37

Table 3-38. Levelized cost - Hospitals

The levelized cost of electricity ranges from 4.8 to 7.7¢/kWh depending on the cost of gas.

Economic Potential

Percent accepting based on payback period is shown as a function of electric rate in Figure 3-32 for buy-deficit/sell-excess mode and as a function of buyback rate in Figure 3-33 for buy-all/sell-all mode.

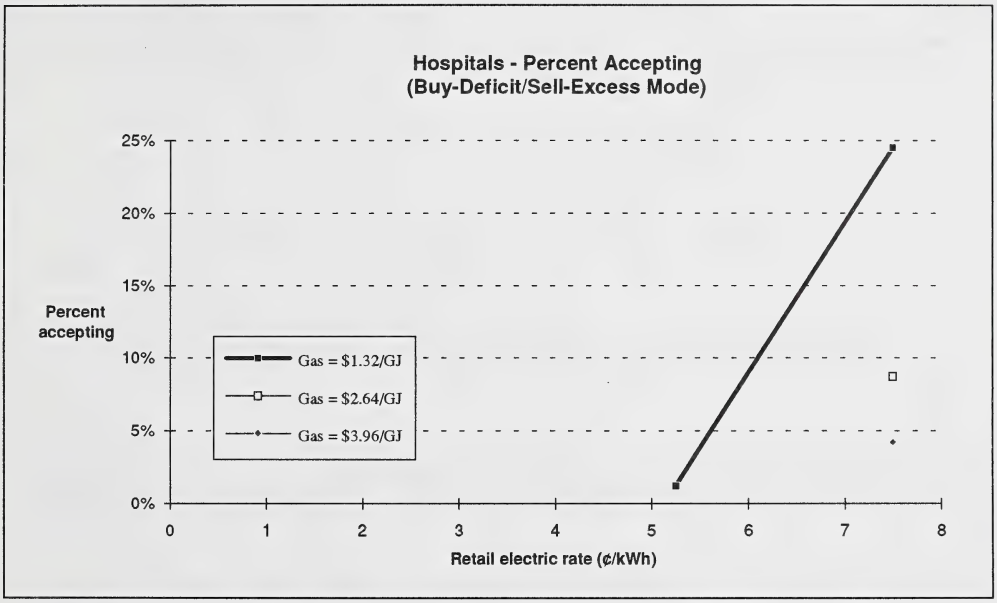

Figure 3-32. Percent accepting - Buy-deficit/sell-excess mode - Hospitals

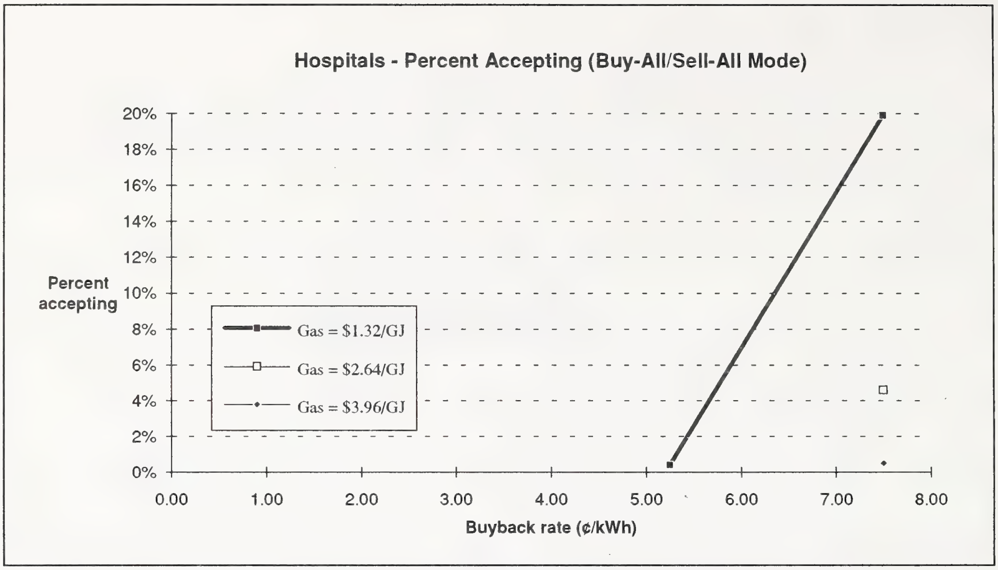

Figure 3-33. Percent accepting - Buy-all/sell-all mode - Hospitals

Table 3-39 summarizes the calculation of technical and economic potential for the 1992 and 2005 scenarios and provides a comparison to current implementation.

	1992		2005	
	Electric Peak	Thermal Peak	Electric Peak	Thermal Peak
Number of Facilities	13		18	
Representative Capacity (MW)	1.33	6.59	1.33	6.59
Technical Potential (MW)	17.29	85.67	23.94	118.62
Percent Accepting	1.2%	0.4%	0.0%	0.0%
Economic Potential (MW)	0.21	0.31	0.00	0.00
1990 Implementation (MW)	22.9			

Table 3-39. Base case summary - Hospitals

Discussion of Results

Our analysis shows the potential for cogeneration in this segment to be very small. Under either operating mode, percent accepting is less than 2% of technical potential for electric rates at 5.25¢/kWh and gas rates at their low 1992 levels. With

gas rates at 2005 levels, there is no economic potential whatsoever. Currently 22.9 MW of capacity is installed at hospitals in Alberta.

Some of this existing capacity may be explained by the need for backup generation in order to improve reliability. The economics of backup generation are very different from those for cogeneration and are not explored here. Some of the capacity may also be explained in terms of the relatively low cost of capital to hospitals.

3.9 Sweet Gas Plants

Gas plants can be divided into 3 different types: sour gas plants with natural gas liquids (NGL) processing, sweet gas plants with NGL processing, and sweet gas plants without NGL processing. This analysis excludes sweet gas plants without NGL processing due to limited opportunities for cogeneration in these plants.

Natural gas production in Alberta is expected to grow from 89.6 billion m^3 in 1990 to 127.5 billion m^3 in 2005.[38] Similar growth is expected in the gas processing industry. The EUPC predicts energy use by gas processing plants to grow by between 1.8% and 4.2% through 2005, from the level of 2119 GWh in 1989. Energy use by gas reprocessing plants is predicted to grow by between 1.4% and 3.2%, from a level of 2439 GWh in 1989.[39]

Most gas plants either have gas turbine drives as the primary drive or the back-up drive for their compressors. Heat recovery from gas turbine drives and sulfur production processes is already being undertaken at many plants. Industry wide, on the average, gas plants are operating at about a 50% load factor. This reflects the fact that the industry is currently in a consolidation phase with equipment being downsized for smaller throughputs.[40] The solvents being used for gas processing are being replaced with others. The new processes require less thermal and electric energy.[41] There may be other plants where cogeneration is economically possible, such as straddle plants. These have not been analyzed here because they are more the exception than the rule.

There are 258 sweet/NGL gas plants in Alberta, processing a total of 65,946 million m^3/year of gas. Of these, 230 process less than 1 million m^3/day of gas. Only those 28 facilities processing more than 1 million m^3/day are considered in this study.

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[38] ERCB. Energy Requirements in Alberta 1991-2005, pp 8-9. Energy Resources Conservation Board: Calgary, 1991.
[39] EUPC. 1990 EUPC Electric Forecast Working Range for Planning Resource Additions. EUPC Forecast Task Force : Calgary Alberta, August 1990.
[40] Discussion with industry experts.
[41] Ibid.

Representative facility characteristics

The processes involved in the typical sweet gas plant include dehydrating, condensate removal, and compression processes. These gas plants may also have a number of gas drives for compressors. Upon review of plants currently operating in Alberta, an average electric demand of 2.7 MW and an average thermal demand of 60 GJ/hr per 10 million m^3/day of raw gas was developed. A facility processing 10 million m^3/day of raw gas was used as the representative facility for this segment.

Many different cogeneration technologies are applicable to gas plants, such as gas engine systems for smaller plants, and gas and steam turbines for larger plants. This analysis was done for the larger plants only using the gas turbine with heat recovery cogeneration technology.

Results of COGENMASTER analysis

Table 3-40 illustrates the systems considered for the two alternative operating modes

Dispatch Mode	Cogeneration Sizing Strategy	System Type	Capacity (MW)
Buy All/Sell All	**Thermal Peak**	**Gas Turbine w/ Heat Recovery**	**7.78**
Buy Def./Sell Excess	Electric Peak	Gas Turbine w/ Heat Recovery	2.70

Table 3-40.System description - Sweet Gas Plants

The number of representative sweet gas plants is predicted to grow from 12 in 1992 to 18 in 2005.[42] The number of representative plants in 1992 (12) does not correspond to the actual number of plants considered (28) because the representative facility is based on processing 10 million m^3/day rather than an average production rate for the 28 plants. If systems are sized to thermal peak, technical potential is 93 MW in 1992 and 140 MW in 2005. If system is sized to electric peak, technical potential is 32 MW in 1992 and 49 MW in 2005.

[42]ERCB. Energy Requirements in Alberta 1991-2005, pp 8-9. Energy Resources Conservation Board: Calgary, 1991.

The results of COGENMASTER runs measuring economic attractiveness of the proposal cogeneration investment are shown in terms of simple payback, internal rate of return, and rate of return on equity in Table 3-41 below. The shaded regions in this table indicate price scenarios for which the cogeneration plant is operated in the buy-all/sell-all mode.

N. Gas ->	A:-$0.05/cu.m. ($1.32/GJ)				B:-$0.10/cu.m. ($2.64/GJ)				C:-$0.15/cu.m. ($3.96/GJ)			
Buyback ¢/kWh->	1.00	3.00	5.25	7.50	1.00	3.00	5.25	7.50	1.00	3.00	5.25	7.50
Electric Rate	Simple Payback (Years)											
R1: 3.0¢/kWh	7.8	6.5	2.8	1.8	20.0	13.0	3.7	2.1	20.0	20.0	5.1	2.5
R2: 5.25¢/kWh	3.1	3.1	2.8	1.8	4.3	4.3	3.7	2.1	7.1	7.1	5.1	2.5
R3: 7.5¢/kWh	1.9	1.9	1.9	1.8	2.3	2.3	2.3	2.1	3.0	3.0	3.0	2.5
	Internal Rate of Return											
R1: 3.0¢/kWh	0.08	0.11	0.25	0.37	0.00	0.03	0.20	0.33	0.00	0.00	0.14	0.28
R2: 5.25¢/kWh	0.23	0.23	0.25	0.37	0.17	0.17	0.20	0.33	0.10	0.10	0.14	0.28
R3: 7.5¢/kWh	0.36	0.36	0.36	0.37	0.30	0.30	0.30	0.33	0.24	0.24	0.24	0.28
	Rate of Return on Equity											
R1: 3.0¢/kWh	0.37	0.51	1.16	1.70	0.00	0.00	0.93	1.49	0.00	0.00	0.68	1.28
R2: 5.25¢/kWh	1.08	1.08	1.16	1.70	0.80	0.80	0.93	1.49	0.44	0.44	0.68	1.28
R3: 7.5¢/kWh	1.62	1.62	1.62	1.70	1.37	1.37	1.37	1.49	1.11	1.11	1.11	1.28

Table 3-41. Economics of cogeneration - Sweet Gas Plants

Figures 3-34 and 3-35 depict the IRR results from Table 3-41 graphically.

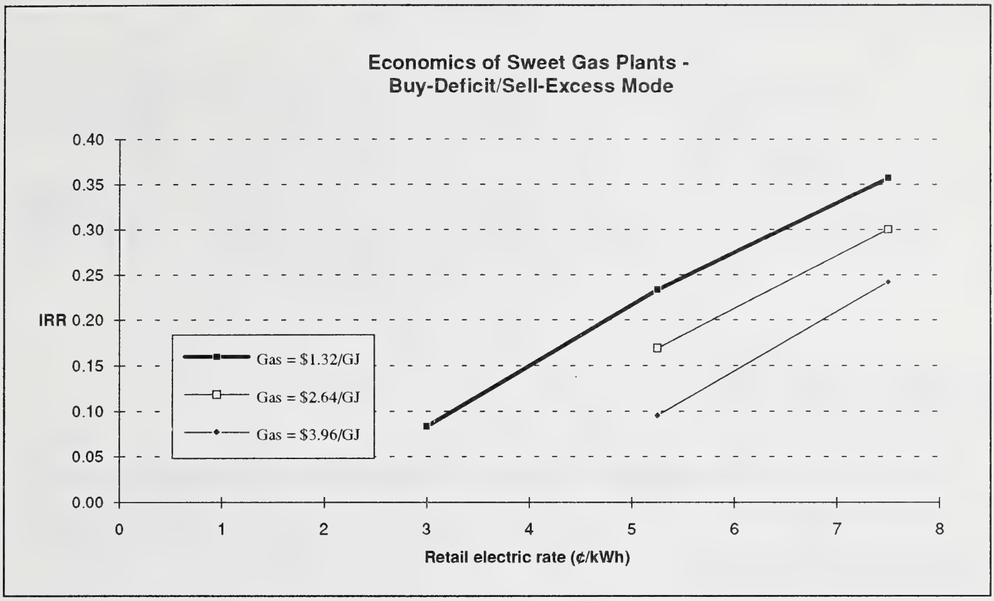

Figure 3-34. Economics - Buy-deficit/sell-excess mode - Sweet Gas Plants

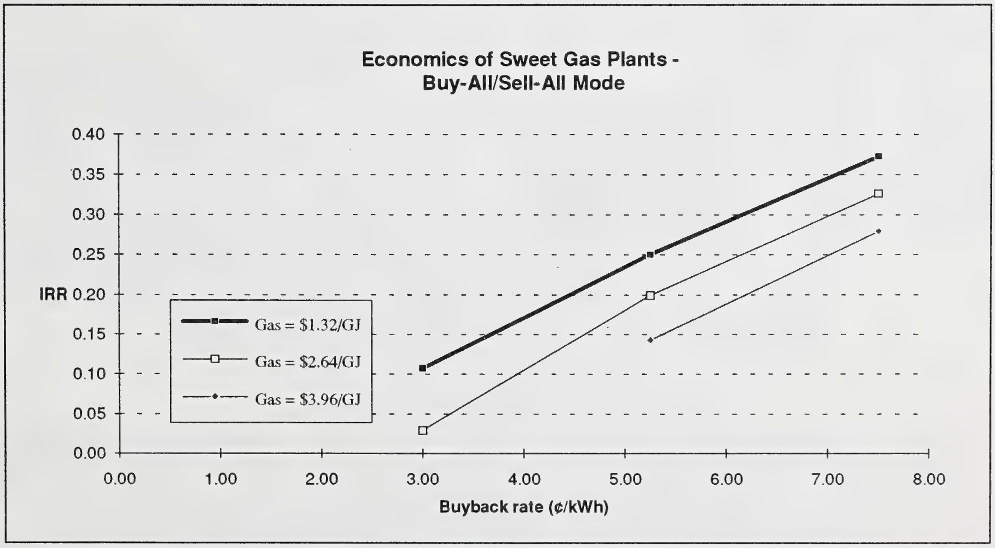

Figure 3-35. Economics - Buy-all/sell-all mode - Sweet Gas Plants

Table 3-42 shows the levelized project cost for each of the two operating mode/sizing options, for two alternative lengths of financing term, and for each of the three levels of gas cost.

N. Gas ->	A:-$0.05/cu.m. ($1.32/GJ)		B:-$0.10/cu.m. ($2.64/GJ)		C:-$0.15/cu.m ($3.96/GJ)	
Discount Rate: 7%	Levelized Cost (¢/kWh)					
Term: 15 yrs	2.72	**2.41**	3.77	**3.29**	4.82	**4.17**
Term: 20 yrs	2.55	**2.25**	3.60	**3.13**	4.65	**4.01**

Table 3-42. Levelized cost - Sweet Gas Plants

Analysis of Potential

Percent accepting based on payback period is shown as a function of electric rate for buy-deficit/sell-excess and buyback rate for buy-all/sell-all modes respectively in Figures 3-36 and 3-37.

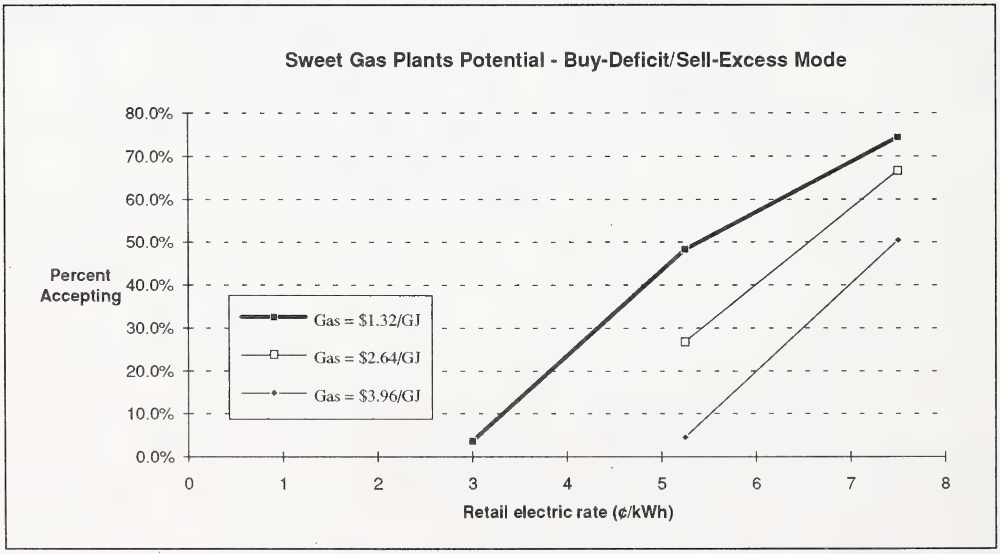

Figure 3-36. Percent accepting - Buy-deficit/sell-excess mode - Sweet Gas Plants

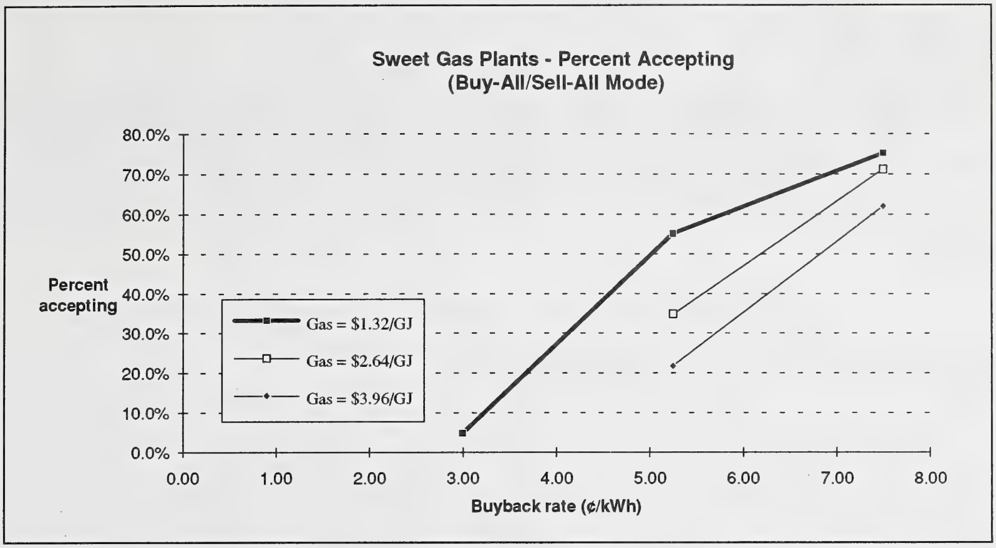

Figure 3-37. Percent accepting - Buy-all/sell-all mode - Sweet Gas Plants

Table 3-43 summarizes the calculation of technical and economic potential for the 1992 and 2005 scenarios and provides a comparison to current implementation.

	1992		2005	
	Electric Peak	Thermal Peak	Electric Peak	Thermal Peak
Number of Facilities	12		18	
Representative Capacity (MW)	2.70	7.80	2.70	7.80
Technical Potential (MW)	32.40	93.60	48.60	140.40
Percent Accepting	3.6%	4.8%	0.0%	0.0%
Economic Potential (MW)	1.15	4.49	0.00	0.00
1990 Implementation (MW)	34*			

*including both sweet and sour plants - data was not available separately

Table 3-43. Base case summary - Sweet Gas Plants

Discussion of Results

Current cogeneration capacity installed at gas plants (sweet and sour combined) is approximately 34 MW. Our analysis indicates that less than 5% of technical potential will eventually be implemented regardless of operating mode if electric rates are at 3¢/kWh. At predicted 2005 gas rates, there is no economic potential in this segment.

3.10 Sour Gas Plants

There are 52 sour/natural gas liquids (NGL) gas plants in Alberta, processing a total of 63,565 million m^3/year of gas. Of these, 18 process less than 1 million m^3/day of gas. Only the 34 facilities processing more than 1 million m^3/day are considered in this study.

Representative facility characteristics

The processes involved in the typical sour gas plant include dehydrating, sweetening, condensate removal, and compression processes. Gas plants may also have a number of gas drives for compressors. Although the plant is a net consumer of electric and thermal energy, some processes generate either useful electric or thermal energy. Therefore, it is not possible to develop a typical energy balance for these plants. Upon review of plants currently operating in Alberta, an average electric demand of 6.5 MW and an average thermal load of 97.4 GJ/hr per 10 million m^3/day of raw gas was developed. A facility processing 10 million m^3/day of raw gas was used as the representative facility for this segment. Typically, the larger gas plants operate at a very high load factor. However, in recent times these plants are operating at much lower than normal capacity. The analysis has been based on plants operating at the high load factors.

Many different cogeneration technologies are applicable to gas plants, such as gas engine systems for smaller plants, and gas and steam turbines for larger plants. This analysis was done for the larger plants only using the gas turbine with heat recovery cogeneration technology.

Results of COGENMASTER analysis

Table 3-44 illustrates systems considered for the two alternative operating modes.

Dispatch Mode	Cogeneration Sizing Strategy	System Type	Capacity (MW)
Buy All/Sell All	**Thermal Peak**	**Gas Turbine w/ Heat Recovery**	**12.63**
Buy Def./Sell Excess	Electric Peak	Gas Turbine w/ Heat Recovery	6.68

Table 3-44. System description - Sour Gas Plants

The analysis assumes that the number of sour gas plants will grow from 16 in 1992 to 23 in 2005.[43] The number of representative plants in 1992 (16) does not correspond to the actual number of plants considered (34) because the representative facility is based on processing 10 million m^3/day rather than an average production rate for the 28 plants. With systems sized to thermal peak, technical potential is 202 MW in 1992 and 290 MW in 2005. With systems sized to electric peak, technical potential is 107 MW in 1992 and 154 MW in 2005.

The results of COGENMASTER runs measuring economic attractiveness of the proposed cogeneration investment are shown in terms of simple payback, internal rate of return, and rate of return on equity in Table 3-45 below. The shaded regions in this table indicate price scenarios for which the cogeneration plant is operated in the buy-all/sell-all mode.

[43]Based on gas consumption projections. Energy Efficiency Branch. A Discussion Paper on the Potential for Reducing Carbon Dioxide Emissions in Alberta: 1988-2005, Alberta Department of Energy: Canada, January 1991.

N. Gas ->	A:-$0.05/cu.m. ($1.32/GJ)				B:-$0.10/cu.m. ($2.64/GJ)				C:-$0.15/cu.m. ($3.96/GJ)			
Buyback ¢/kWh->	1.00	3.00	5.25	7.50	1.00	3.00	5.25	7.50	1.00	3.00	5.25	7.50
Electric Rate	Simple Payback (Years)											
R1: 3.0¢/kWh	7.3	6.4	2.8	1.8	20.0	12.8	3.6	2.1	20.0	20.0	5.0	2.5
R2: 5.25¢/kWh	3.0	3.0	2.8	1.8	4.1	4.1	3.6	2.1	6.7	6.7	5.0	2.5
R3: 7.5¢/kWh	1.9	1.9	1.9	1.8	2.3	2.3	2.3	2.1	2.9	2.9	2.9	2.5
	Internal Rate of Return											
R1: 3.0¢/kWh	0.09	0.11	0.25	0.37	0.00	0.03	0.20	0.33	0.00	0.00	0.14	0.28
R2: 5.25¢/kWh	0.24	0.24	0.25	0.37	0.18	0.18	0.20	0.33	0.10	0.10	0.14	0.28
R3: 7.5¢/kWh	0.36	0.36	0.36	0.37	0.31	0.31	0.31	0.33	0.25	0.25	0.25	0.28
	Rate of Return on Equity											
R1: 3.0¢/kWh	0.42	0.51	1.16	1.70	0.00	0.00	0.93	1.49	0.00	0.00	0.68	1.28
R2: 5.25¢/kWh	1.10	1.10	1.16	1.70	0.83	0.83	0.93	1.49	0.49	0.49	0.68	1.28
R3: 7.5¢/kWh	1.65	1.65	1.65	1.70	1.40	1.40	1.40	1.49	1.14	1.14	1.14	1.28

Table 3-45. Economics of cogeneration - Sour Gas Plants

Figures 3-38 and 3-39 depict the IRR results from Table 3-45 graphically.

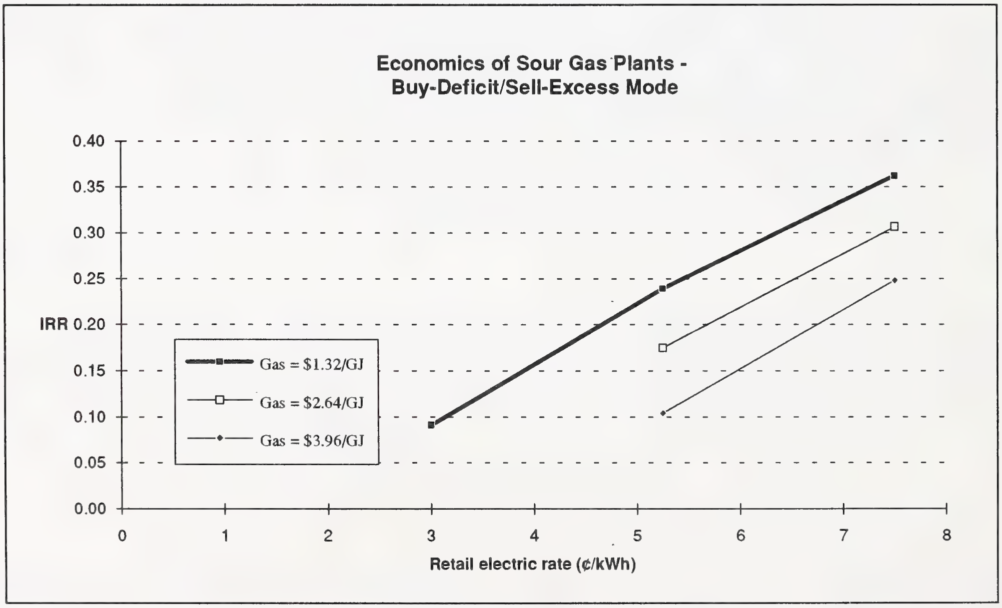

Figure 3-38. Economics - Buy-deficit/sell-excess mode - Sour Gas Plants

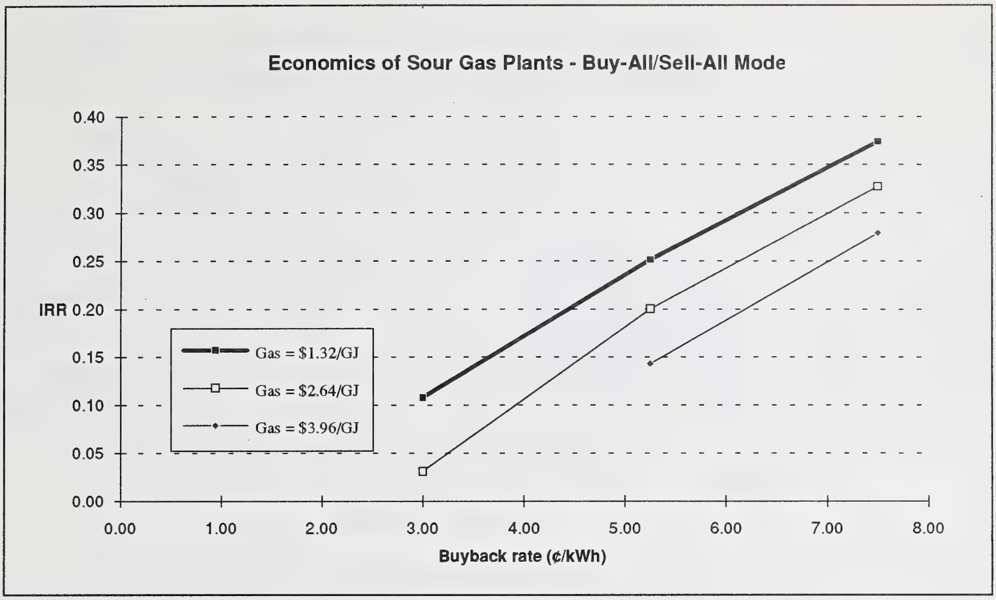

Figure 3-39. Economics - Buy-all/sell-all mode - Sour Gas Plants

Table 3-46 shows the levelized project costs for each of the two operating mode/sizing options, for two alternative lengths of financing term, and for each of the three levels of gas costs.

N. Gas ->	A:-$0.05/cu.m. ($1.32/GJ)		B:-$0.10/cu.m. ($2.64/GJ)		C:-$0.15/cu.m ($3.96/GJ)	
Discount Rate: 7%	Levelized Cost (¢/kWh)					
Term: 15 yrs	2.62	2.40	3.66	3.28	4.71	4.16
Term: 20 yrs	2.45	2.23	3.50	3.11	4.55	3.99

Table 3-46. Levelized cost - Sour Gas Plants

Analysis of Potential

Percent accepting based on payback period is shown as a function of electric rate and buyback rate for buy-deficit/sell-excess and buy-all/sell-all modes respectively in Figures 3-40 and 3-41.

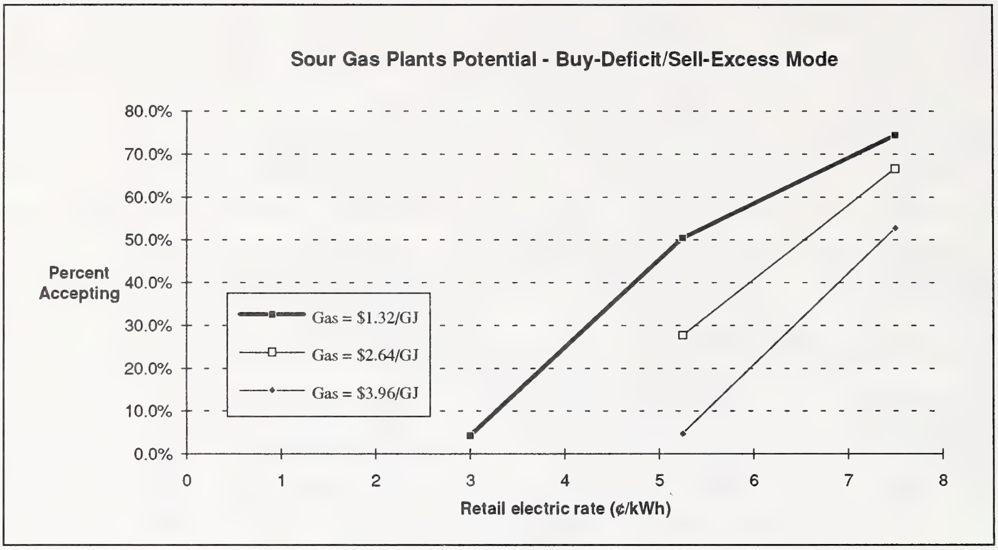

Figure 3-40. Percent accepting - Buy-deficit/sell-excess mode - Sour Gas Plants

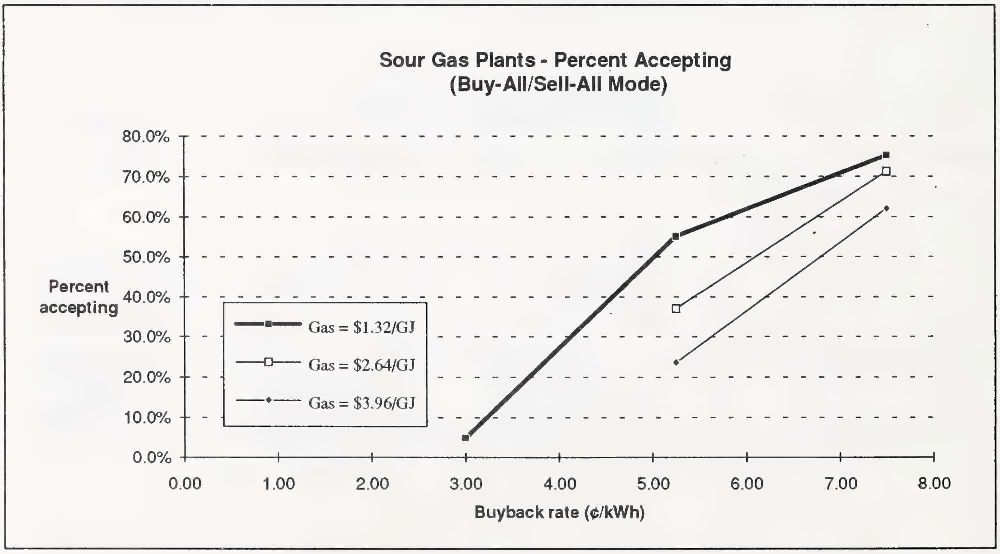

Figure 3-41. Percent accepting - Buy-all/sell-all mode - Sour Gas Plants

Table 3-47 summarizes the calculation of technical and economic potential for the 1992 and 2005 scenarios and provides a comparison to current implementation.

	1992		2005	
	Electric Peak	Thermal Peak	Electric Peak	Thermal Peak
Number of Facilities	16		23	
Representative Capacity (MW)	6.70	12.60	6.70	12.60
Technical Potential (MW)	107.2	201.60	154.10	289.80
Percent Accepting	4.2%	4.8%	0.0%	0.0%
Economic Potential (MW)	4.51	9.76	0.00	0.00
1990 Implementation (MW)	34*			

*including both sweet and sour gas plants - data was not available separately

Table 3-47. Base case summary - Sour Gas Plants

Discussion of Results

Current cogeneration capacity installed at gas plants (sweet and sour combined) is approximately 34 MW. Our analysis indicates that economic potential is less than 5% of technical potential for electric rates of 3¢/kWh and 1992 gas rates. Economic potential is zero for the higher gas rates predicted for 2005. The economics of sweet and sour gas plants are very similar, and neither segment appears particularly favorable to cogeneration. However, there may be some potential not reflected in this analysis if these plants have access to fuel valued significantly below market rates.

3.11 Food Processing/Breweries

The food industry consumes approximately 5 percent of the total electric sales to the commercial sector. There are 367 electric customers, of which 14 have a demand greater than 2 MW[44]. This industry is characterized by small facilities, with less than 50 of the firms having more than 100 employees each.

The consumer profile provided electric and gas consumption for the food industry as a whole, and did not segment the market any further. Based on the listing of firms by employee size, meat processing and packing is the single major type of food processing industry in Alberta. The meat processing industry represents about half of the total processed food shipments[45]. The other major sub-group is the beverage industry, including distilleries and breweries.

The diverse nature of the food industry, the relatively small size of the industry, and the lack of detailed information on the production and energy consumption by sub-group does not allow a very rigorous analysis of this industry to be conducted. The economic analysis for the food industry was done for a representative meat processing plant and a representative malt beverage plant. The economic characteristics of these plants were found to be essentially identical, so only one set of economic data is presented.

Representative Facility Characteristics

The meat processing and packing facility requires electricity for lights, rendering, process preparation, cooking , packing, refrigeration and other miscellaneous uses. The fuel (gas) use in these facilities is for space heating, singers, smoke houses, cooking ovens, and hot water. The representative meat processing and packing facility is assumed to have an average hourly demand of 2.2 MW. The corresponding average

[44]Electricity Policy Branch. Cogeneration and Waste Energy Generation Policy Study, Alberta Department of Energy: Canada, March 1992.
[45]Industry and Resources Alberta, 1990

hourly thermal load, in the form of steam and hot water, that can be displaced by cogeneration is 14.7 GJ.[46]

The malt beverage facility requires electricity for mechanical power, refrigeration, compressed air, lighting and other miscellaneous uses. The fuel (gas) use in these facilities is mainly for drying, space heating, and process heating. The representative malt beverage facility is assumed to have an average hourly demand of 2.2 MW. The corresponding average hourly thermal load, in the form of steam and hot water, that can be displaced by cogeneration is 13 GJ.[47]

The most applicable technology for this segment is the gas engine, although small gas turbines can also be used in the larger facilities. The analysis has been done using the gas engine cogeneration system. The total cogeneration system capacity in many of these facilities may exceed a few megawatts in some cases. In such cases, multiple gas engines are assumed to be installed to increase the overall system reliability.

Results of COGENMASTER Analysis

The results of the COGENMASTER analysis appear in Tables 3-48 through 3-50 below and are summarized in Appendix B. Table 3-48 illustrates the systems considered for the two alternative operating modes.

Operating Mode	Cogeneration Sizing Strategy	System Type	Capacity (MW)
Buy All/Sell All	**Thermal Peak**	**Gas Engine w/ Heat Recovery**	**5.06**
Buy Def./Sell Excess	Electric Peak	Gas Engine w/ Heat Recovery	2.20

Table 3-48. System description - Food industry

[46]Derived from energy use by process in the food industry in the book titled *Energy-Saving Techniques for the Food Industry,* edited by M.E. Casper, Noyes Data Corporation, New Jersey, 1977.
[47]Ibid.

The number of facilities in the segment is predicted to grow from 14 in 1992 to 19 in 2005.[48] If facilities are sized to peak thermal load, technical potential is 71 MW in 1992 and 96 MW in 2005. If facilities are sized to electric peak, technical potential is 31 MW in 1992 and 42 MW in 2005.

The results of COGENMASTER runs measuring economic attractiveness of the proposed cogeneration investment are shown in terms of simple payback, internal rate of return, and rate of return on equity in Table 3-49 below. The shaded regions in this table indicate price scenarios for which the cogeneration plant is operated in the buy-all/sell-all mode.

N. Gas ->	**A:-$0.05/cu.m. ($1.32/GJ)**				**B:-$0.10/cu.m. ($2.64/GJ)**				**C:-$0.15/cu.m. ($3.96/GJ)**			
Buyback ¢/kWh->	1.00	3.00	5.25	7.50	1.00	3.00	5.25	7.50	1.00	3.00	5.25	7.50
Electric Rate	**Simple Payback (Years)**											
R1: 3.0¢/kWh	20.0	20.0	8.6	4.7	20.0	20.0	11.2	5.3	20.0	20.0	15.9	6.2
R2: 5.25¢/kWh	9.1	9.1	8.6	4.7	12.8	12.8	11.2	5.3	20.0	20.0	15.9	6.2
R3: 7.5¢/kWh	4.8	4.8	4.8	4.7	5.7	5.7	5.7	5.3	6.9	6.9	6.9	6.2
	Internal Rate of Return											
R1: 3.0¢/kWh	0.00	0.00	0.07	0.16	0.00	0.00	0.04	0.13	0.00	0.00	0.01	0.11
R2: 5.25¢/kWh	0.07	0.07	0.07	0.16	0.03	0.03	0.04	0.13	0.00	0.00	0.01	0.11
R3: 7.5¢/kWh	0.15	0.15	0.15	0.16	0.13	0.13	0.13	0.13	0.10	0.10	0.10	0.11
	Rate of Return on Equity											
R1: 3.0¢/kWh	0.00	0.00	0.09	0.29	0.00	0.00	0.04	0.23	0.00	0.00	0.00	0.18
R2: 5.25¢/kWh	0.08	0.08	0.09	0.29	0.02	0.02	0.04	0.23	0.00	0.00	0.00	0.18
R3: 7.5¢/kWh	0.28	0.28	0.28	0.29	0.21	0.21	0.21	0.23	0.14	0.14	0.14	0.18

Table 3-49. Economics of cogeneration - Food industry

[48]Based on ERCB GDP growth projections. ERCB. 1991 Annual Electricity Statistics Report, Energy Resources Conservation Board: Calgary, 1991.

Figures 3-42 and 3-43 depict the IRR results from Table 3-49 graphically for the buy-deficit/sell-excess mode and the buy-all/sell-all mode respectively.

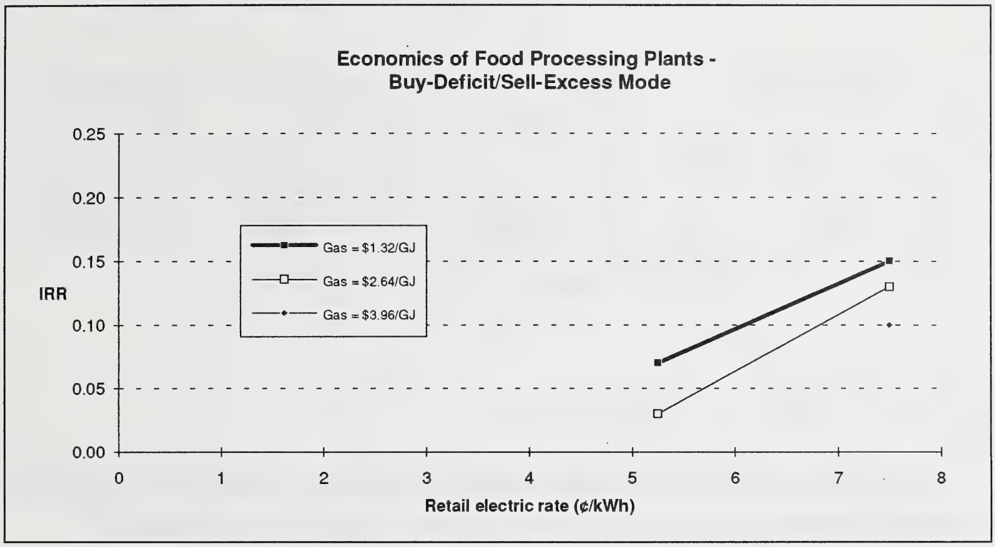

Figure 3-42. Economics - Buy-deficit/sell-excess mode - Food industry

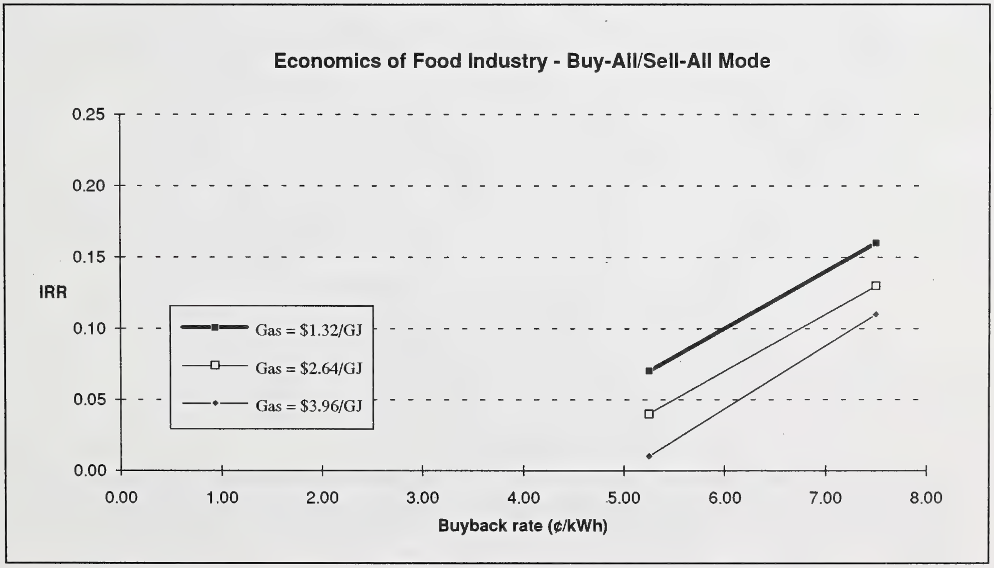

Figure 3-43. Economics - Buy-all/sell-all mode - Food industry

Table 3-50 shows the levelized project cost for each of the two operating mode/sizing options, for two alternative lengths of financing term, and for each of the three levels of gas costs.

N. Gas ->	A:-$0.05/cu.m. ($1.32/GJ)		B:-$0.10/cu.m. ($2.64/GJ)		C:-$0.15/cu.m ($3.96/GJ)	
Discount Rate: 7%	Levelized Cost (¢/kWh)					
Term: 15 yrs	5.08	**4.95**	5.81	**5.55**	6.54	**6.16**
Term: 20 yrs	4.75	**4.62**	5.48	**5.22**	6.21	**5.83**

Table 3-50. Levelized cost - Food industry

Economic Potential

Percent accepting based on payback period is shown as a function of electric rate for buy-deficit/sell-excess mode and buy-all/sell-all mode respectively in Figures 3-44 and 3-45.

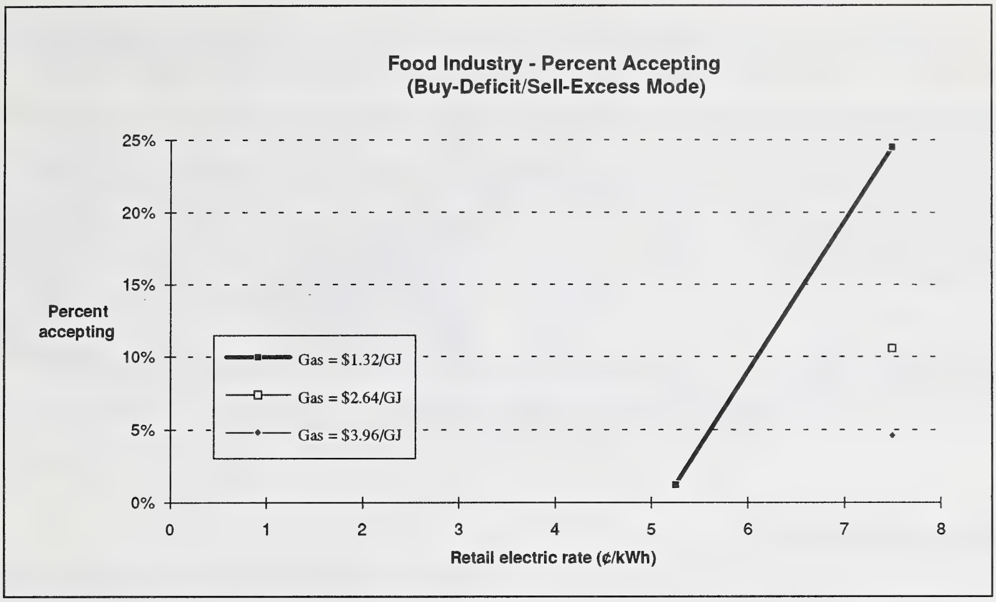

Figure 3-44. Percent accepting - Buy-deficit/sell-excess - Food industry

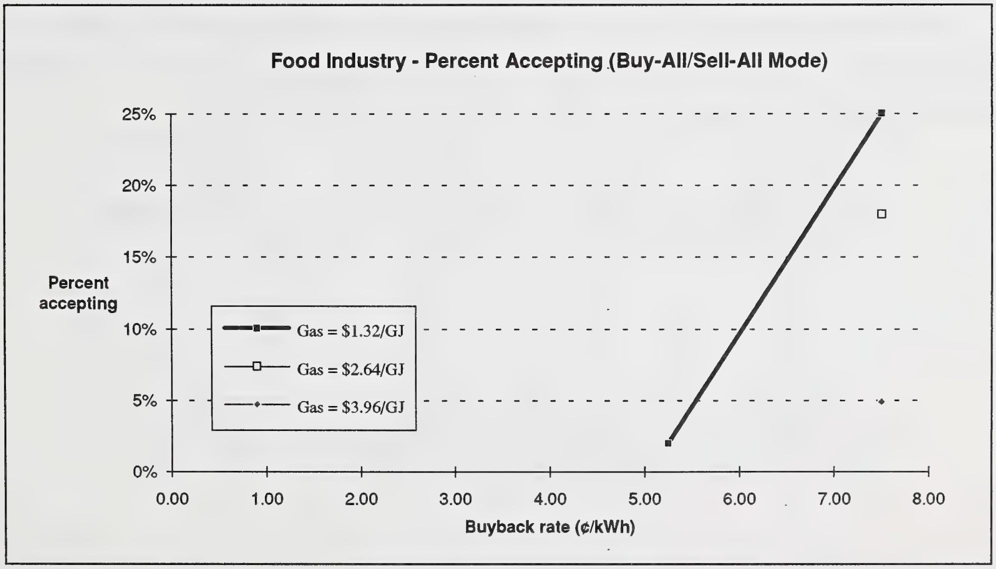

Figure 3-45. Percent accepting - Buy-all/sell-all mode - Food industry

Table 3-51 summarizes the calculation of technical and economic potential for the 1992 and 2005 scenarios and provides a comparison to current implementation.

	1992		2005	
	Electric Peak	Thermal Peak	Electric Peak	Thermal Peak
Number of Facilities	14		19	
Representative Capacity (MW)	2.20	5.06	2.20	5.06
Technical Potential (MW)	30.80	70.84	41.80	96.14
Percent Accepting	0.0%	0.0%	0.0%	0.0%
Economic Potential (MW)	0.00	0.00	0.00	0.00
1990 Implementation (MW)	6.3			

Table 3-51. Base case summary - Food industry

Discussion of Results

Our analysis indicates that there is no economic potential in this segment at current electric and gas prices or at the higher gas prices predicted for 2005.

Current cogeneration capacity installed at food processing plants/breweries is approximately 6.3 MW.[49] This capacity is installed at a sugar plant and is explained by a need to dispose of waste, a motivation not captured in our analysis.

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[49]ERCB. 1991 Annual Electricity Statistics Report, Energy Resources Conservation Board: Calgary, 1991.

3.12 Turbo Expanders

A turbo expander is a machine in which a gas or fluid at high pressure is allowed to expand to a lower pressure, thereby producing mechanical work. The focus of this analysis will be the generation of power using the turbo expander as a pressure reducing valve in gas transmission and distribution pipelines at city gates or at the gates of large industrial and commercial gas consumers.

The analysis performed here is based on a 1985 study commissioned by major gas transmission and distribution companies.[50] The study showed the number of potential sites suitable for the installation of turbo expanders.

Representative Facility Characteristics

The size distribution of these sites as identified in the aforementioned study and the capacity we will assume for each range in the size distribution is illustrated in Table 3-52. The total amount of technically possible generation from turbo expanders in Alberta (considering neither project economics nor market acceptance) is 16.75 MW.

Electric Capacity Range (kW)	Average Capacity Assumed (kW)	Number of Sites	Technical Potential (MW)
< 100	50	22	1.10
100 - 200	150	12	1.80
200 - 500	350	16	5.60
500 - 1,000	750	3	2.25
> 1,000	1,200	5	6.00
TOTAL	288.79	58	16.75

Table 3-52. Size distribution of potential turboexpander sites

The installed cost of turbo expanders ranges from $800 to $1,200/kW according to the manufacturer[51] The midpoint of this range, $1000/kW, has been used as the

[50]R.A. Winsor and T.H. Barmby, Turbo Expanders: Applications and Future Potential, presented at the Canadian Gas Association's Sixth National Technical Conference at Vancouver, February 26, 1991.
[51]Ibid.

installed cost of the equipment for the base case 1992 and 2005 scenarios. Results are also shown for a high cost scenario, wherein the installed cost is assumed to be fifty percent higher ($1500/kW).

The use of a turbo expander results in a drop in the temperature of the gas exiting the turbo expander. There are operational constraints on the discharge temperature to prevent ground freezing or to keep the gas out of the hydrate formation zone. Additional energy has to be supplied to preheat the discharge gas. About 700 cubic meters (25 Mcf) of gas is required per kW capacity per year for preheating.[52] The maintenance cost is estimated at 2 percent of the installed cost of the unit.[53] In this analysis, a maintenance cost of $0.005/kWh is used.

Results of COGENMASTER Analysis

Tables 3-53 and 3-54 show the payback periods for turbo expanders for both cost scenarios and different electric buyback and gas rates.

	Simple Payback (Years) Buyback Rate			
Gas Price	1¢/kWh	3¢/kWh	5.25¢/kWh	7.5¢/kWh
$0.05/GJ	20.0	5.4	2.6	1.7
$0.10/GJ	20.0	6.7	2.9	1.8
$0.15/GJ	20.0	8.8	3.2	2.0

Table 3-53. Economics of turboexpanders - base case

[52]React Turbo Expander Manufacturer data.
[53]Ibid.

Gas Price	Simple Payback (Years) Buyback Rate 1¢/kWh	3¢/kWh	5.25¢/kWh	7.5¢/kWh
$0.05/GJ	20.0	8.2	3.9	2.6
$0.10/GJ	20.0	10.1	4.3	2.8
$0.15/GJ	20.0	13.2	4.8	3.0

Table 3-54. Economics of turboexpanders - high capital cost case

Figures 3-46 and 3-47 depict payback as a function of buyback rate for the two capital cost levels.

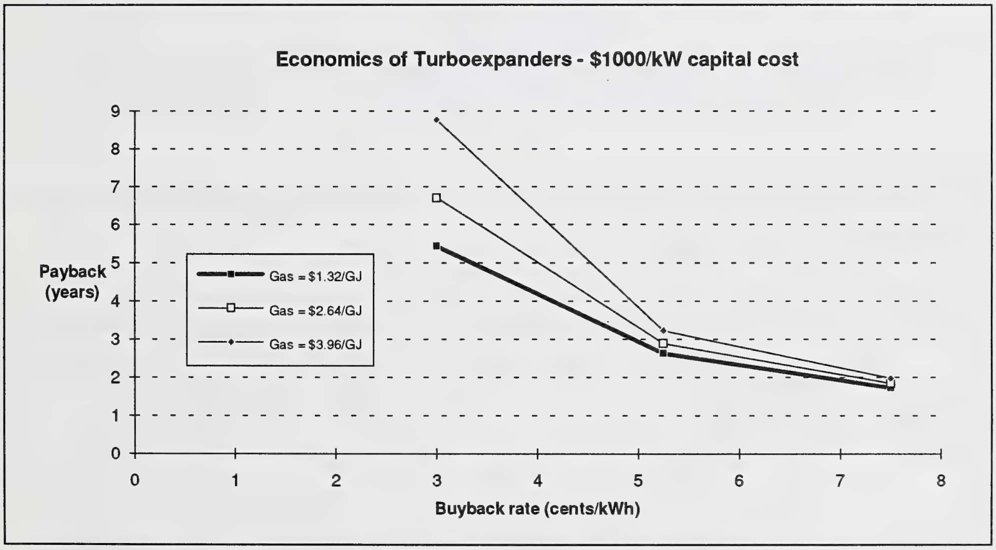

Figure 3-46. Economics of turboexpanders - base case

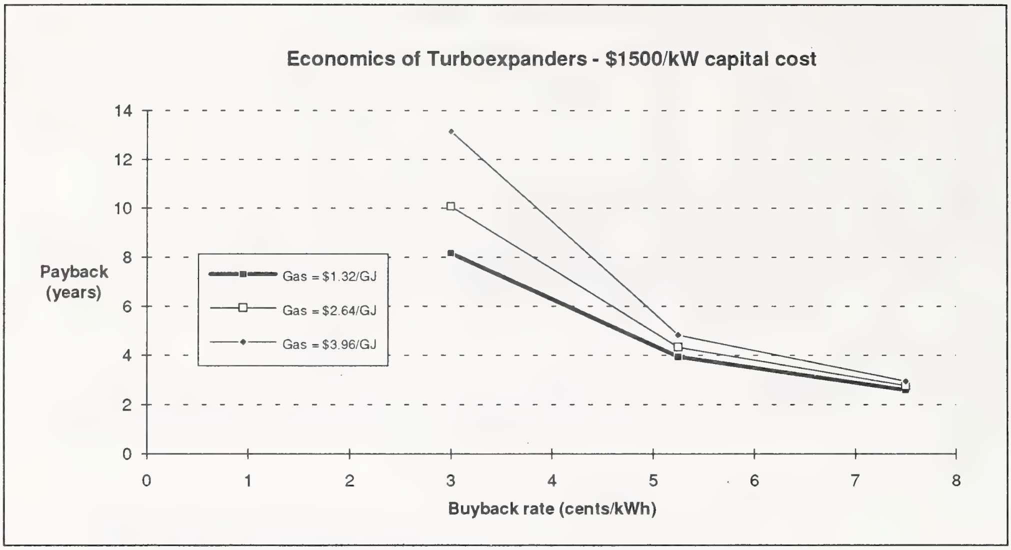

Figure 3-47. Economics of turboexpanders - high capital cost case

Table 3-55 depicts levelized costs for the two alternative capital cost levels and for two lengths of equipment life.

	N. Gas -> Discount Rate: 7%	A: -$0.05/cu.m. ($1.32/GJ)	B: -$0.10/cu.m. ($2.64/GJ)	C: -$0.15/cu.m. ($3.96/GJ)
Capital Cost	Term	Levelized Cost (¢/kWh)		
$1000/kW	15 yrs	2.07	2.47	2.87
	20 yrs	1.91	2.31	2.71
$1500/kW	15 yrs	2.66	3.06	3.46
	20 yrs	2.41	2.81	3.21

Table 3-55. Levelized cost - Turboexpanders

Analysis of Potential

Percent accepting based on payback is shown as a function of electric rate in Figures 3-48 and 3-49.

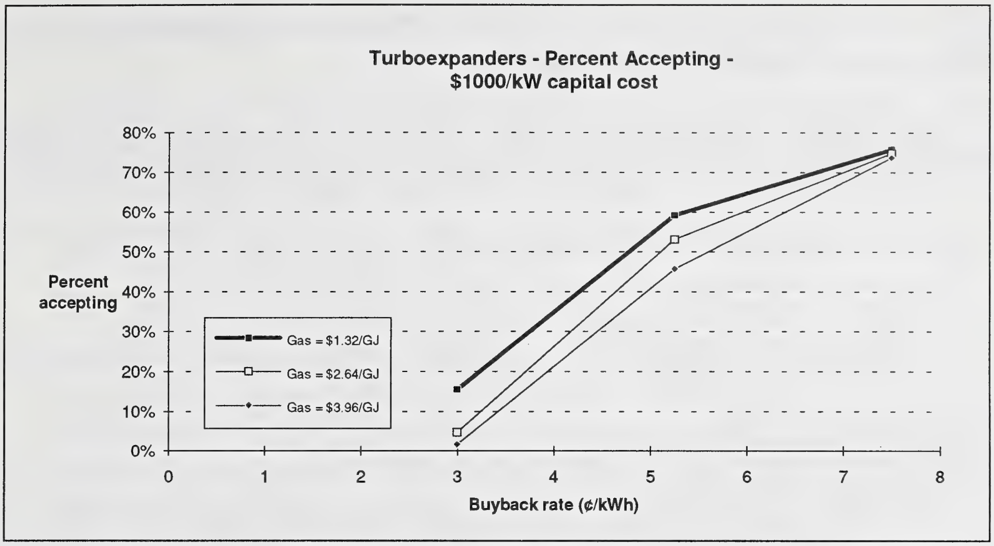

Figure 3-48. Market acceptance - turboexpanders - base case

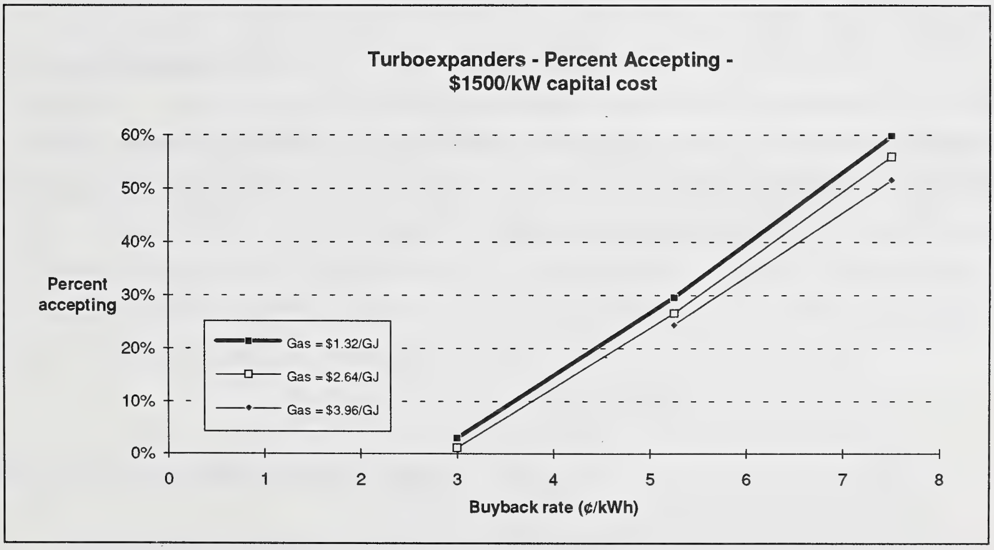

Figure 3-49. Market acceptance - turboexpanders - high capital cost case

At a buyback rate of 3¢/kWh, less than 5% of turbo expander projects with capital costs of $1500/kw will appear economically attractive in the 1992 scenario. About 15% of projects will appear attractive if capital costs are lower ($1000/kW). In

the 2005 scenario (higher gas rates) less than 5% of projects are economically attractive even for a capital cost of $1,000/kW.

Table 3-56 summarizes the calculation of technical and economic potential for the 1992 and 2005 scenarios and provides a comparison to current implementation.

	1992	2005
Number of Facilities	58	90
Representative Capacity (MW)	0.29	0.29
Technical Potential (MW)	16.82	26.10
Percent Accepting	16.2%	4.7%
Economic Potential (MW)	2.72	1.23
1990 Implementation (MW)	0	

Table 3-56. Base case summary - Turboexpanders

Discussion of Results

The amount of technically possible cogeneration (16.75MW) appears to be a significant overstatement of the amount of cogeneration that is economic. The actual buyback rate received by these projects is in the range of 1 to 2¢/kWh. Noise and the need for energy enhancement at expanders are likely to limit installation. Only a few demonstration units were in place as of 1991.

3.13 Saw, Panelboard, and CTMP Mills

Sawmills, CTMP paper mills, and panelboard mills in Alberta produce over 1.5 million tonnes of residue, much of which is currently disposed of - primarily in beehive burners, silo burners, or power boilers. These residues could potentially be used for power generation. Currently, no on-site generation is installed at these facilities.[54]

Representative Facility Characteristics

This segment will be analyzed for waste to power generation potential rather than for cogeneration potential. Sawmills and panelboard mills typically have very small thermal requirements, incapable of utilizing all the waste heat from any cogeneration plant. As stated earlier, CTMP mills are not analyzed for cogeneration potential because they do not have an adequate match between electric and thermal requirements. If CTMP mills were integrated with paper mills, it is possible that the integrated operation would present an opportunity for cogeneration. This possibility is not examined in this report.

The power plant assumed for the representative facility is a wood fired steam turbine generating plant with a capacity of 20MW. Because of the added complexity of burning wood in the steam boilers and because this is a stand-alone facility, the cost of the plants is substantially higher than that of gas fired steam boilers. The installed cost of the power plant is estimated to be $2,300/kW capacity.[55] The analysis excludes the effect of supplemental firing with natural gas.

Results of COGENMASTER Analysis

Scaling the representative facility up to the size of the segment requires 14 facilities in 1992 and 16 facilities in 2005. Thus total technical potential is 280 MW in 1992 and 320 MW in 2005. This scaling assumes 100% of waste wood residue is

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[54]Levelton study.

[55]"Woodlands Technology and Residue Disposal/Utilization", Proceedings of the Forestry Conference '91, Edmonton, Alberta.

available for use as fuel. As such, waste wood haul distance is ignored. However, the figure of 1.5 million tonnes of residue is probably low as some mills were in partial production when the data was gathered. We assume these two effects offset each other.

The results of COGENMASTER runs measuring economic attractiveness of the proposed generation investment are shown in terms of simple payback, internal rate of return, and rate of return on equity in Table 3-57 below.

Wood ->	A: -$10/tonne				B: $0/tonne				C:$10/tonne			
Buyback ¢/kWh->	1.00	3.00	5.25	7.50	1.00	3.00	5.25	7.50	1.00	3.00	5.25	7.50
Simple Payback (Years)	20.0	20.0	9.2	5.5	20.0	20.0	11.3	6.2	20.0	20.0	14.6	7.1
Internal Rate of Return	0.00	0.00	0.06	0.13	0.00	0.00	0.04	0.11	0.00	0.00	0.02	0.09
Rate of Return on Equity	0.00	0.00	0.22	0.61	0.00	0.00	0.04	0.53	0.00	0.00	0.00	0.44

Table 3-57. Economics of Saw, Panelboard, and CTMP Mills

Figure 3-50 depicts the IRR results from Table 3-57 graphically.

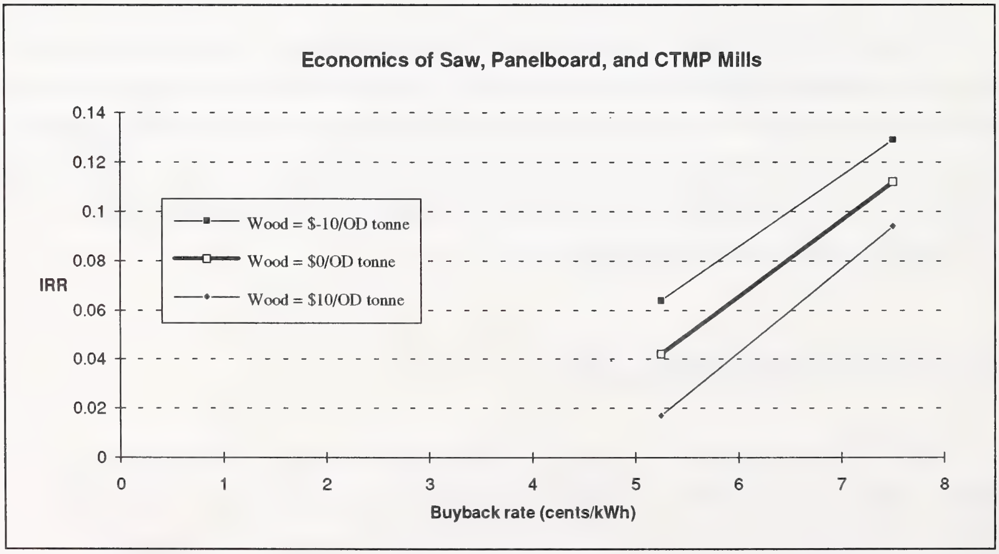

Figure 3-50. Economics of Saw, Panelboard, and CTMP Mills

The power plant facility is assumed to be independent of the sawmill. Therefore, the analysis is dependent only on the buyback price for electricity, and not dependent on the retail price of electricity. As would be expected, higher wood prices tend to make the economics of the system poorer. The economics are not as sensitive to the price of the wood residue as they are to the buyback price of electricity. However, a high tipping fee may be required to make such projects economic.

Table 3-58 shows the levelized project cost for two alternative lengths of financing term, and for each of the three levels of wood costs.

Wood ->	**A:-$10/tonne**	**B:$0/tonne**	**C:$10/tonne**
Discount Rate: 7%	Levelized Cost (¢/kWh)		
Term: 15 yrs	4.64	5.27	5.89
Term: 20 yrs	4.20	4.83	5.45

Table 3-58 Levelized cost - Saw, Panelboard, and CTMP Mills

The levelized cost of electricity ranges from 4.2 to 5.9¢/kWh depending on the cost of wood and the financing term.

Analysis of Potential

Percent accepting based on payback period is shown as a function of electric rate in Figure 3-51.

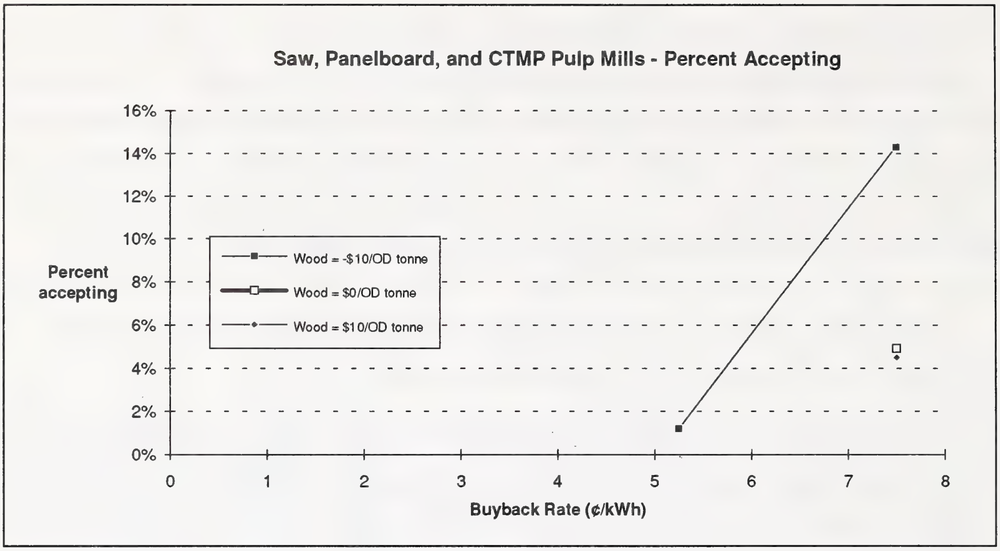

Figure 3-51. Market acceptance - Saw, Panelboard, and CTMP Mills

Table 3-59 summarizes the calculation of technical and economic potential for the 1992 and 2005 scenarios and provides a comparison to current implementation.

	1992	2005
Number of Facilities	14	16
Representative Capacity (MW)	20.00	20.00
Technical Potential (MW)	280.00	320.00
Percent Accepting	0.0%	0.0%
Economic Potential (MW)	0.00	0.00
1990 Implementation (MW)	0	

Table 3-59. Base case summary - Saw, Panelboard, and CTMP Mills

Discussion of Results

There is currently no generation installed using wood residue from sawmills, panelboard mills, or CTMP mills in Alberta. Our analysis shows that even with a tipping fee of $10.00/tonne none of the technically possible waste wood generation facilities are economically attractive at predicted electric rates (3¢/kWh).

3.14 Gas Flares

Gas flares flaring less than 150,000 m^3/month are excluded from this analysis because their small size makes cogeneration uneconomic. Gas flares with high sulfur content are also excluded from the analysis because it may be uneconomic to burn sour gas due to equipment degradation. There are 127 sites flaring sweet gas at more than 150,000 m^3/month for a total of 37,718,800 m^3/month flared at such sites. The average amount of gas flared at these sites is 3,563,981 m^3/year.[56]

Representative facility characteristics

As stated above, the average amount of gas flared at the 127 sites considered is 3,563,981 m^3/year. This analysis assumes that 0.48m^3 of flare gas are required per kWh of electricity generated. At an 80% load factor, the size of the generating unit at the average site is approximately 1.059 MW.

The only applicable technology is a gas engine. Two alternative levels of capital cost are investigated in this analysis. The low capital cost level is $750/kW and the high capital cost level is $1,125/kW.

Results of COGENMASTER analysis

The analysis assumes a royalty charge of 2¢/m^3 on the gas flared. The results of the analysis for each of three electric buyback rates and each of the two capital cost levels considered appear in Table 3-60 below.

[56]Energy Resources Conservation Board Gas Department data.

Buyback Price	3 ¢/kWh	5.25 ¢/kWh	7.5 ¢/kWh
Electric Revenue	222,749	389,810	556,872
Gas Royalty Charge (@ $0.02053 per m^3)	73,169	73,169	73,169
Equipment Maintenance Cost (@ 2.0¢/kWh)	148,499	148,499	148,499
Gross Revenues with Gas Royalty Charge	1,081	168,143	335,204
LOW COST SCENARIO - BASE CASE			
Capital Cost: $750 per kW	794,623	794,623	794,623
Simple Payback	735.0	4.7	2.4
Percent Accepting	0.0%	24.8%	65.0%
HIGH COST SCENARIO			
Capital Cost: $1,125 per kW	1,191,935	1,191,935	1,191,935
Simple Payback	1102.5	7.1	3.6
Percent Accepting	0.0%	4.5%	38.0%

Table 3-60. Economics and market acceptance - Gas flares

Figure 3-52 depicts the payback results from Table 3-60 graphically.

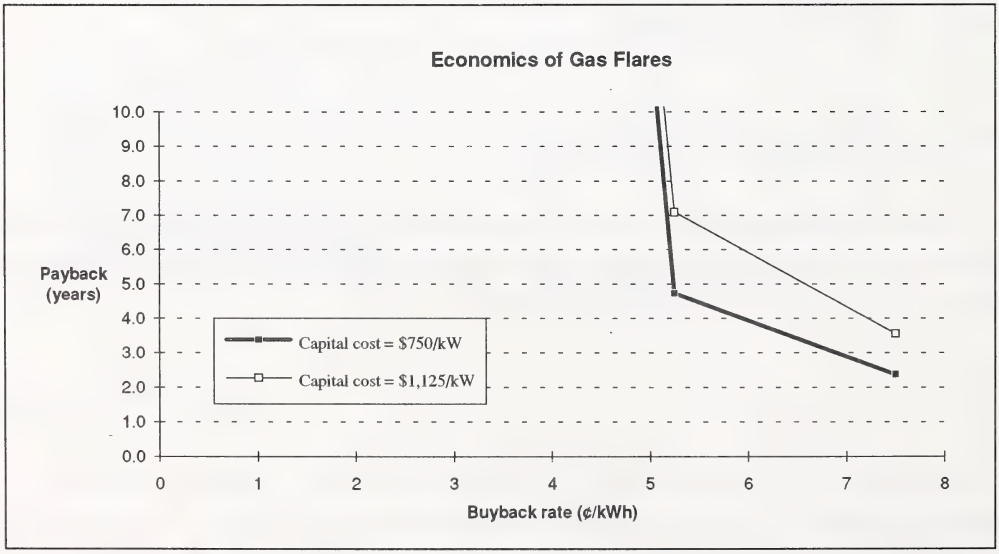

Figure 3-52. Economics of gas flares

Table 3-61 shows the levelized cost for two alternative lifetimes and for both capital cost levels.

Capital Cost ->	$750/kW	$1,125/kW
Discount Rate: 7%	Levelized Cost (¢/kWh)	
Term: 15 yrs	4.08	4.63
Term: 20 yrs	3.93	4.40

Table 3-61. Levelized cost - gas flares

Analysis of Potential

Percent accepting is shown as a function of buyback rate for the two capital cost scenarios in Figure 3-53 below.

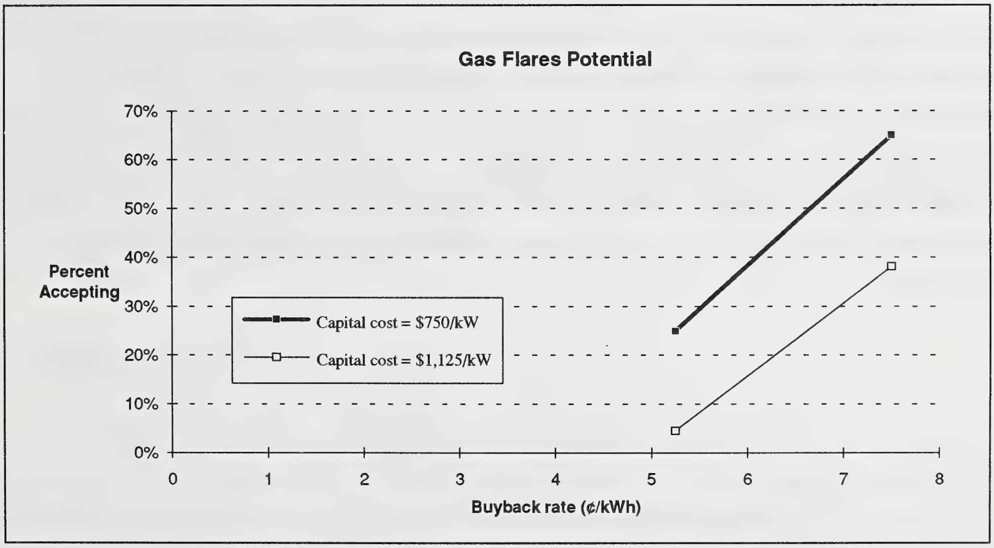

Figure 3-53. Market acceptance of gas flares

Table 3-62 summarizes the calculation of technical and economic potential for the 1992 and 2005 scenarios and provides a comparison to current implementation.

	1992	2005
Number of Facilities	127	127
Representative Capacity (MW)	1.06	1.06
Technical Potential (MW)	134.62	134.62
Percent Accepting	0.0%	0.0%
Economic Potential (MW)	0.00	0.00
1990 Implementation (MW)	0	

Table 3-62. Base case summary - Gas flares

Discussion of Results

Gas flare generation is found to be uneconomic at a buyback rate of 3¢/kWh even at the low capital cost level. In fact, the economics of gas flaring are such that only about 25% of technically possible gas flaring installations are expected to be implemented even if buyback rates reach 5.25¢/kWh and capital cost is only $750/kW. This analysis fails to consider the degradation of flare volume over time, the impact of risk in flare lifetime, and the impact of low quality gas on equipment life. All of these factors would be expected to decrease the economic attractiveness of gas flare generation.

3.15 Municipal Solid Waste

Incineration of solid waste is typically practiced for the purpose of reducing the total quantity of refuse that has to be hauled to the landfill. Energy recovery from solid waste has also been in practice from the beginning of the century. However, it has not been cost-effective to recover the energy because of the availability of low cost conventional fuel. This section deals with the economics and potential for the generation of electricity from solid waste.

Solid waste includes a wide range of materials such as municipal solid waste, hospital and toxic waste, automobile tires, used automotive oil, wood residue in sawmills and paper mills, and peat bogs. This section will deal only with municipal solid waste.

The quantity of waste generated annually in the cities of Edmonton and Calgary is estimated to be 902 kg per capita, 689 kg per capita in other cities with populations over 10,000, and 617 kg per capita in rural areas and smaller communities[57]. Alberta's population in 1991 is estimated to be 2,535,200[58]. Edmonton and Calgary account for 614,665 (24.2%) and 708,593 (28.0%) respectively[59]. 349,227 (13.8%) of the population live in other cities with over 10,000 people. The remaining 862,715 (34.0%) live in rural areas and smaller communities.

Representative Facility Characteristics

The average amount of municipal waste generated in Edmonton and Calgary are 1,519 and 1,751 tonnes per day respectively, 659 tonnes per day is generated in other cities with populations over 10,000[60]. Rural areas and smaller communities generate about 1,458 tonnes per day. Technical in this segment is based on the assumption that all of the waste from Edmonton and Calgary and half the waste from other cities with populations over 10,000 can be burned in MSW energy recovery plants.

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[57]Data from1988 Study of Potential for Waste Recycling in Alberta
[58]Statistics, Canada, July 1991
[59]Population statistics from Alberta Municipal Affairs data as of June 30, 1991
[60]Based on population and per capita waste generated.

There are many different types of municipal solid waste energy recovery plants that generate electricity. One type is the mass-burning plant which includes modular plants, water-wall incinerators, refractory-lined incinerators. Another type is the refuse-derived fuel plant. The larger the size of the plant, the better the economics for the plant. A mass burning plant that has a capacity of handling 1,360 tonnes per day will have an electrical capacity of 40 MW and can generate 300 million kWh per year[61]. The capital cost of the plant is estimated at $240 million, based on $6,000/kW. The capital cost is very high due to extensive materials handling equipment and low fuel quality. The maintenance cost, including fixed and variable components, is estimated at 2.5¢/kWh[62].

Results of Analysis

The number of representative facilities is assumed to grow from 2.6 in 1992 to 3 in 2005. This corresponds to a growth in technical potential from 104 MW in 1992 to 120 MW in 2005. An analysis showing revenues from electricity sales, revenue from tipping fees (fees received by the MSW plant to dispose of waste) and net revenues is shown in Table 3-63 below.

Annual Revenues (million $)				
	Tipping Fee ($/tonne)	$20	$35	$50
Buyback Price (¢/kWh)	Revenue (million $)	12.0	21.1	30.1
1.0	3.0	7.5	16.6	25.6
3.0	9.0	13.5	22.6	31.6
5.25	15.8	20.3	29.3	38.4
7.5	22.5	27.0	36.1	45.1

Note: Revenues have been adjusted for $7.5 million annual O&M cost

Table 3-63. Revenue breakdown for MSW plants

[61]Technology Assessment Guide, Electricity Supply, Prepared by Utility Planning Methods Center, prepared for Electric Power Research Institute, November 1989.

[62]Adjusted to 1991 Canadian dollars.

Simple payback in each of the buyback rate/tipping fee scenarios is shown in Table 3-64.

Simple Payback (years)			
	Tipping Fee ($/tonne)		
Buyback Price (¢/kWh)	20	35	50
1.0	31.8	14.5	9.4
3.0	17.7	10.6	7.6
5.25	11.8	8.2	6.3
7.5	8.9	6.7	5.3

Based on capital cost of $240 million ($6,000/kW)

Table 3-64. Economics of MSW plants

Figure 3-54 depicts the results from Table 3-64 graphically.

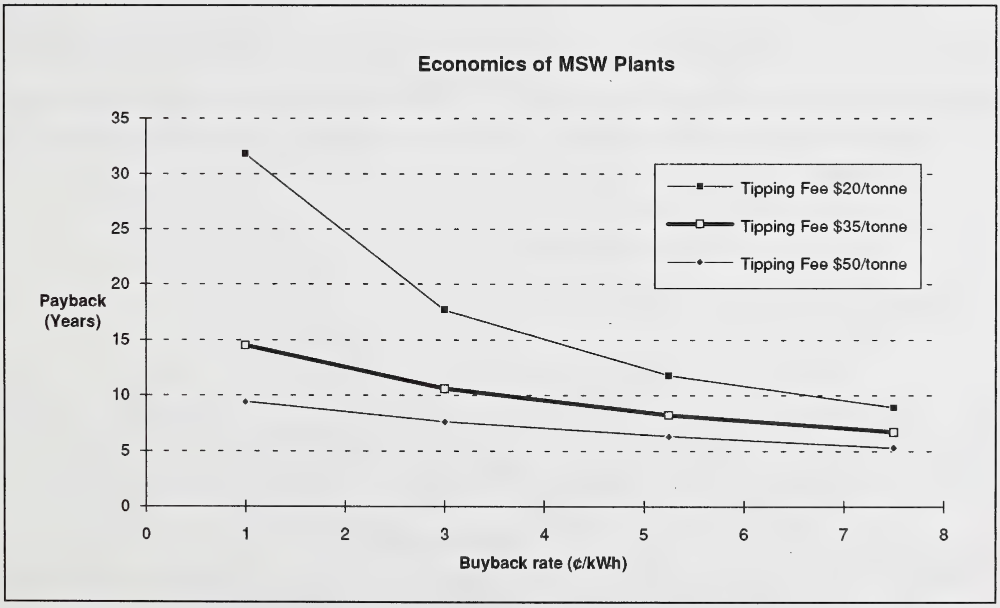

Figure 3-54. Economics of MSW plants

The economics are sensitive to both the waste tipping fee and the buyback price of electricity. A high tipping fee may be required to make such projects economic.

Levelized costs are shown in Table 3-65 for each of two alternative lengths of equipment life.

Discount Rate: 7%	Levelized Cost (¢/kWh)	
Tipping Fee	$20/OD tonne	$35/OD tonne
Term: 15 yrs	6.69	3.68
Term: 20 yrs	5.53	2.53

Table 3-65. Levelized cost - MSW plants

Economic Potential

Percent accepting based on payback period is shown as a function of electric rate in Figure 3-55.

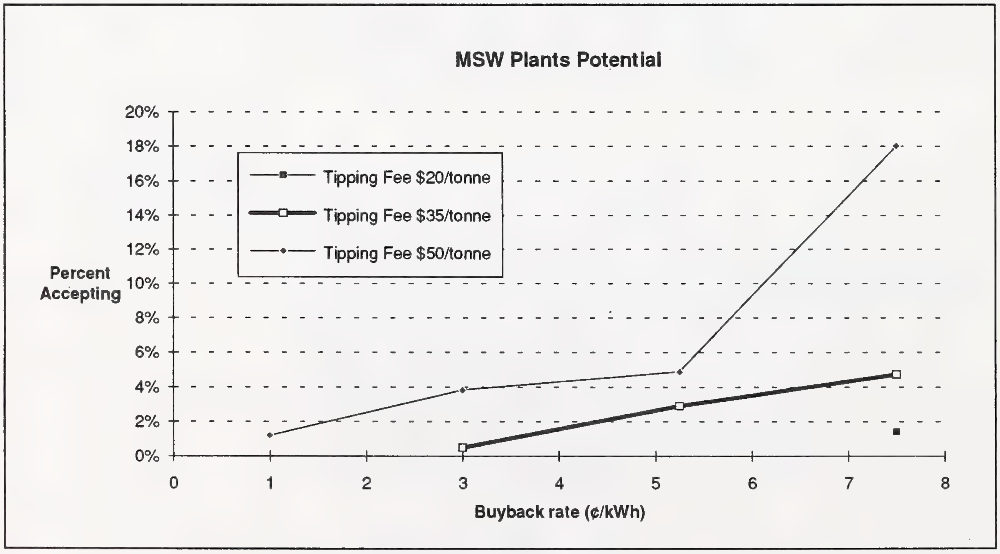

Figure 3-55. Market acceptance of MSW plants

Table 3-66 summarizes the calculation of technical and economic potential for the 1992 and 2005 scenarios and provides a comparison to current implementation.

	1992	2005
Number of Facilities	2.6	3
Representative Capacity (MW)	40.00	40.00
Technical Potential (MW)	104.00	120.00
Percent Accepting	0.4%	0.4%
Economic Potential (MW)	0.46	0.53
1990 Implementation (MW)	0	

Table 3-66. Base case summary - MSW plants

Discussion of Results

Less than 1% of technical potential is economic in the 1992 and 2005 base case scenarios (buyback rate equals 3¢/kWh, tipping fee equals $35/tonne). Only about 4% of technical potential is expected to be economic at a buyback rate of 3¢/kWh even with tipping fees as high as $50 per tonne. This segment faces a number of barriers including high capital costs, uncertainty in O&M cost, and difficulties in siting that will tend to further discourage implementation. Of course it is possible that a municipality could decide to make such a project economic by setting very high tipping fees.

3.16 Discussion of Other Segments

Several segments included in the consumer profile were not analyzed in detail. These are Cement/Concrete; Coal; Metals, Mining, Other Industrial; and Other Commercial. Of these segments Cement/Concrete seemed the most favorable because the relatively high gas use shown in the consumer profile (approximately 7 million GJ by 7 large customers) indicates high heat loads. However, a California Energy Commission study [63] indicated that only 3% of the load at Cement facilities was displaceable through cogeneration. The Other Commercial segment was seen a poor candidate for cogeneration because of the lack of coincidence between heat and electric loads. Neither the team nor the industry, through the stakeholder meetings, identified any significant cogeneration potential in the Coal or Metals, Mining, Other Industrial segments. Note that these two segments comprise less than 5% of total electric power use and less than 1% of total gas use in the consumer profile. Thus any missed potential in these segments would have a minor affect on the study's results.

Two end-use segments that were emphasized by stakeholders were examined more closely by the team. These are the greenhouse and district heating segments. Neither of these segments represent current large heat users in Alberta. Development of the segments would be driven by the opportunity to create new uses for the waste heat from generation and gain economic efficiency through combined operations.

Several sources were examined for information on greenhouses as a significant source for cogeneration potential; however, neither Canadian or U.S. publications[64] indicated that greenhouses are likely to be significant. The team also contacted the Alberta Department of Agriculture[65] for information on greenhouse economics and the potential for greenhouse development. A study conducted by Alberta Agriculture indicated that, while potential existed for the expansion of greenhouses in Alberta, fuel costs for space heating represented only 8 to 10% of operating costs and savings on

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[63] *Forecasts of Annual Capacities of the Supply of Electricity Likely to be Available (LTBA) From Qualifying Facilities Not Subject to CEC Jurisdiction,* CEC, February 11, 1988.

[64] Major sources examined were *Industrial Cogeneration in Canada: Prospects and Perspectives*, CERI, Study No. 24, 1987 and *Industrial and Commercial Cogeneration*, U.S. Office of Technology Assessment, February 1983.

[65] Information from telephone contacts with Mr. Nabi Chaudhary of Alberta Agriculture, Production Economics Branch.

fuel would not be an important driver of expansion. The study also indicated that the typical greenhouse was small, less than one acre of structure and consuming 20,000 to 30,000 GJ of gas. However, a few large 4 to 6 acre facilities exist. A preliminary review suggests that a facility of this size could use a high proportion of the waste heat from a 20 to 25 MW generating plant. However, viability would depend upon the market for the greenhouse produce.

Edmonton Power has proposed a district heating plan for a number of facilities in and around downtown Edmonton[66]. The key potential benefits sited for this facility are more efficient energy use and resulting lower environmental emissions (CO_2, NO_2, and SO_2). The estimated increase in efficiency in moving from an electric-only power plant to a combined-heat-and-power plant is 52% (33% heat utilized in the electric-only power plant and 85% of heat utilized in a combined plant). The electric facility on which the plant is based is 281 MW. The estimated thermal size is between 300 and 750 MW of thermal power (the higher thermal output is accompanied by a re-powering of the electric plant).

This segment could not be examined in the same way as other segments for a number of reasons. First, the present heat load does not correspond to the heat load to be served by the project. The heat load will be developed by combining the winter heat loads of diverse facilities and by creating a new summer load by installing cooling systems that also utilize waste heat. Estimates of this combined heat load and its pattern were outside the scope of this project, and data for a similar facility to be used as prototype could not be located. (Information on heating-only programs is more widely available.) Finally, the team did not have good information on which to base the costs of distributing the heat from its central source.

A 1980 study of district heating indicated a limited future in the U.S.[67] Only 16% of U.S. utilities with district heating planned to expand their systems, 8% planned to phase out, and 62% planned no change. The study found a number of factors that make the economics of U.S. systems very different from the European systems that are widely developed. Factors promoting district heat in Europe include: state funding and subsidy of systems, mandated connection of new facilities, dependence on imported oil,

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[66]Edmonton Power presentation materials.

[67]*Dual Energy Use Systems -- District Heating Survey*, EPRI, EM-1436, July 1980.

and high energy costs. A particular concern in the U.S. was the cost of new distribution systems. At the time of the study, estimates of these costs ranged from $820 US to $4920 US per meter (15 centimeter to 61 centimeter pipe). With low energy costs in Alberta, new technologies are not likely to be economically viable unless they have significantly reduced capital, installation and management costs.

4.0 Sensitivity to Risk and Other Factors

This section considers the impact of uncertainties and penetration on cogeneration and generation-from-waste potential. The section consists of three parts:

- The first part analyzes the sensitivity of the total forecast to uncertainties with broad impacts. These uncertainties include gas price, capital costs, environmental costs, variance in payback, and the payback acceptance curve.
- The second part considers the effects of uncertainties that are expected to have particularly strong impacts on individual sectors. These uncertainties include capital costs, maintenance costs, economic life, and interest rate.
- The last part of this section examines the phenomenon of penetration and its potential influence on the actual implementation of cogeneration and waste energy generation.

4.1 Sensitivity Scenarios

This sub-section examines uncertainties with broad impacts. The prices of the major inputs (e.g., fuel and capital equipment) and outputs (e.g., electricity) directly affect cogeneration economics and thus economic potential. Sensitivity to electric rates was illustrated previously in the summary section. Here, we first examine the individual effects of gas price and capital costs on economic potential. We then present a scenario that assumes there are multiple price changes due to stricter environmental controls. Finally, we examine the sensitivity of potential to the assumption of uniformity within sectors and to changes in decision makers' basic economic criteria.

Sensitivity to Gas Price

The summary graphs at the beginning of this paper relate economic potential to electric rate with gas prices assumed to be fixed. Sensitivity to gas price is illustrated in Figure 4-1 below for various levels of electric rate.

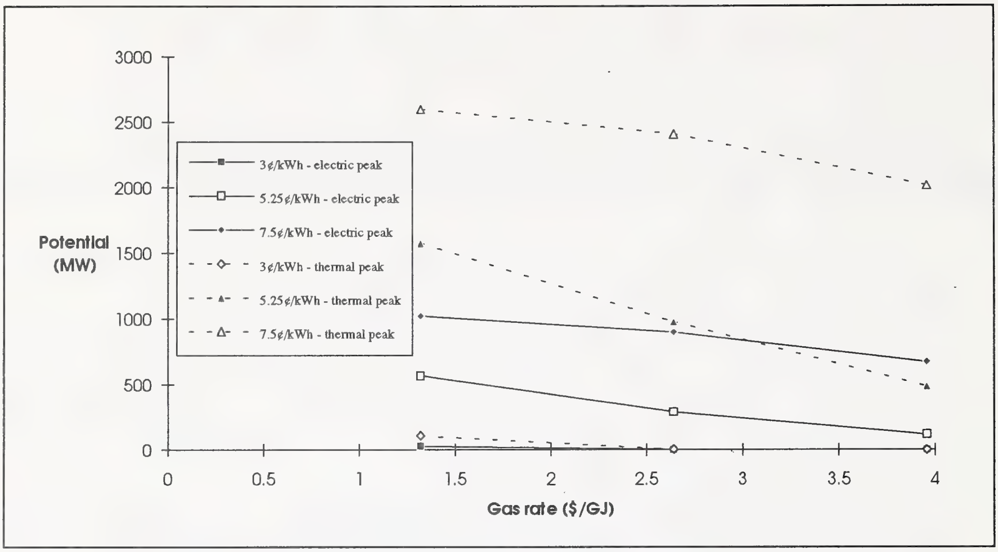

Figure 4-1. Sensitivity of 1992 economic potential to gas price

Tables 4-1 and 4-2 summarize economic potential under various gas and electric rates. Table 4-1 shows economic potential assuming cogeneration systems size to electric peak, while Table 4-2 shows potential assuming systems size to thermal peak. Note that at low electric rates potential is highly sensitive to gas prices. At low electric rates, high gas prices virtually eliminate cogeneration. At high electric rates, gas prices have relatively less impact on a percentage basis but much greater absolute impacts. Details by sector on the impacts of gas rates are presented in Appendix C in Tables C-1 and C-2.

Economic Potential (MW)	Size to Peak Electric		
	Electric Rate		
Gas Price	3¢/kWh	5.25¢/kWh	7.5¢/kWh
$1.32/GJ	28	566	1021
$2.64/GJ	1	289	894
$3.96/GJ	1	118	670

Table 4-1. 1992 economic potential and gas price - electric peak sizing

Economic Potential (MW)	Size to Peak Thermal		
	Buyback Rate		
Gas Price	3¢/kWh	5.25¢/kWh	7.5¢/kWh
$1.32/GJ	109	1577	2598
$2.64/GJ	3	977	2406
$3.96/GJ	3	484	2011

Table 4-2. 1992 economic potential and gas price - thermal peak sizing

Sensitivity to Capital Costs

The base case analysis defines base case capital cost levels for each segment. Some stakeholders have suggested that these capital costs are too high, and this alternative scenario considers this possibility. In this scenario, capital costs are reduced by 25% for each segment. All other parameters of the analysis are the same as in the 1992 base case. As in the 1992 analysis the commercial electric rate is assumed to be 2.25¢/kWh higher than the industrial rate.

Total economic potential is illustrated as a function of electric rates in Figure 4-2 below.

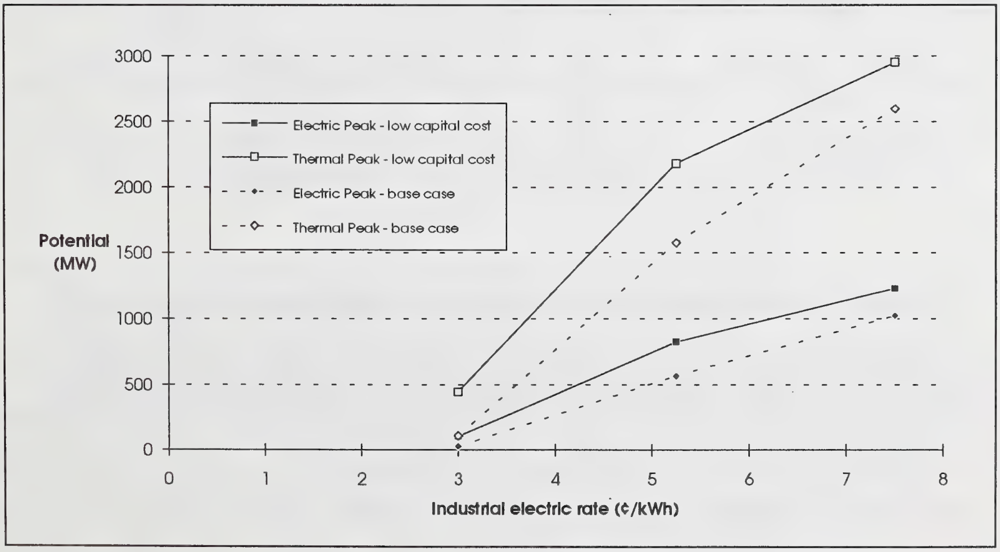

Figure 4-2. 1992 economic potential - lower capital cost scenario

Tables 4-3 and 4-4 show economic potential for the lower capital cost scenario

Economic Potential (MW)	Size to Peak Electric		
	Electric Rate		
Year	3¢/kWh	5.25¢/kWh	7.5¢/kWh
1992	103	824	1229
2005	15	953	2165

Table 4-3. Economic potential at lower capital cost - electric peak

Economic Potential (MW)	Size to Peak Thermal		
	Buyback Rate		
Year	3¢/kWh	5.25¢/kWh	7.5¢/kWh
1992	446	2178	2952
2005	59	3207	5533

Table 4-4. Economic potential at lower capital cost - thermal peak

Table 4-5 compares the results for the two alternative levels of capital costs for the 1992 and the 2005 scenario.

Economic Potential (MW)	Size to Peak Electric		Size to Peak Thermal	
	Year		Year	
Capital Cost Level	1992	2005	1992	2005
Base	28	2	109	4
Low capital cost	103	15	446	59

Table 4-5. Comparison of base case with lower capital cost scenario

At the current low electric rates, a change in capital costs can have a large percentage impact on the amount of cogeneration and generation from wastes. Detailed results by sector can be found in Appendix C in Tables C-3 through C-5.

Sensitivity to Environmental Costs

The intention of the environmental scenario is to examine the possibility of higher electric rates and waste disposal tipping fees due to more stringent environmental controls. The base case analysis assumes a cost of \$0/tonne for wood waste and a tipping fee of \$35/tonne for MSW. In this alternative scenario, tipping fees of \$10/tonne and \$50/tonne are assumed for wood waste and MSW respectively. The base case analysis assumes a cost of 3¢/kWh for industrial electricity (both retail and buyback). This scenario assumes a higher cost of 5.25¢/kWh (both retail and buyback). All other parameters of the analysis are the same as in the 1992 base case.

Total economic potential is illustrated for the base case and environmental scenarios in Figure 4-3 below.

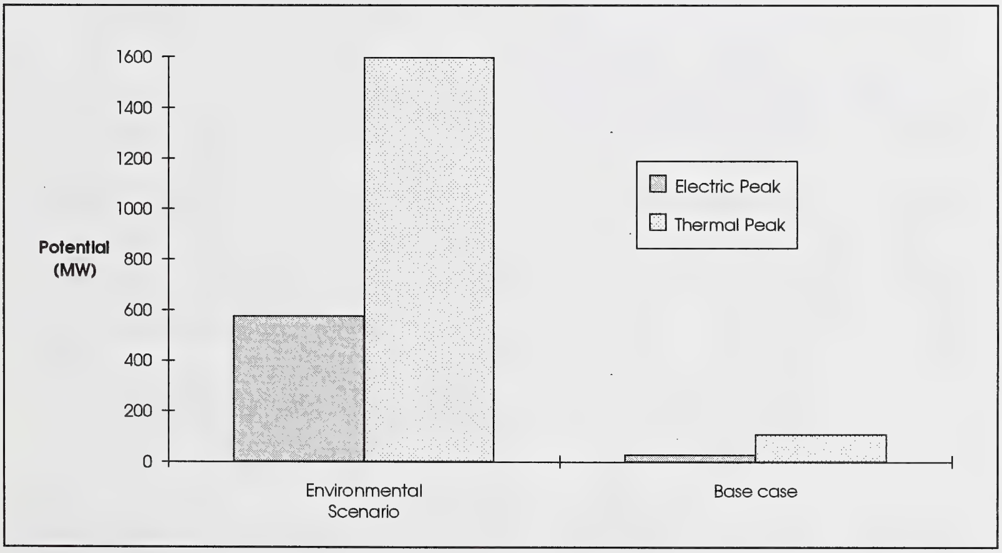

Figure 4-3. Economic potential at base case and environmental scenario

Economic potential is greatly increased in the environmental case; however, most of the increase is due to the higher electric rates resulting from more stringent environmental controls. The impact of the increase in waste generation tipping fees on overall potential is very minor relative to the impact of the increase in electric rates.

Economic potential for the environmental scenario is shown in Tables 4-6 and 4-7 below. Data are given for all electric price levels in order to allow the impact of higher tipping fees and higher electric rates to be seen independently.

Economic Potential (MW)	Size to Peak Electric		
	Electric Rate		
Year	3¢/kWh	5.25¢/kWh	7.5¢/kWh
1992	34	575	1071
2005	9	511	1719

Table 4-6. Economic potential at base case and higher tipping fees - electric peak

Economic Potential (MW)	Size to Peak Thermal		
	Buyback Rate		
Year	3¢/kWh	5.25¢/kWh	7.5¢/kWh
1992	121	1596	2655
2005	21	1916	4761

Table 4-7. Economic potential at base case and higher tipping fees - thermal peak

A comparison of potential for the 1992 and 2005 scenarios between the base case and the environmental scenario is shown in Table 4-8. In this table, the electric rate for the environmental scenario is assumed to be 5.25¢/kWh for industrial customers and 7.5¢/kWh for commercial customers. With sizing to electric peak, the potential increases from 28 MW in the base case to 575 MW in the environmental scenario. With sizing to thermal peak, the potential increases from 109 MW to 1596 MW.

Economic Potential (MW)	Size to Peak Electric		Size to Peak Thermal	
	Year		Year	
Scenario	1992	2005	1992	2005
Base Case	28	2	109	4
Environmental	575	511	1596	1916

Table 4-8. Comparison of economic potential - base case and environmental scenario

Detailed results by sector are provided in Appendix C in Tables C-6 through C-8.

Sensitivity to Variance in Payback

One assumption inherent in the approach of this report is that the economics of a segment are uniform and can be adequately captured by the economics of a typical facility. In reality, however, the economics of cogeneration or generation from waste may vary significantly from facility to facility within a segment. Such variations may be caused by different sources for gas supplies, different costs for capital equipment, different system designs or operating procedures, etc. The purpose of this section is to analyze the impact of payback variation within segments upon the total economic potential for cogeneration and generation from waste. This section concentrates on the 1992 scenario with cogeneration facilities sized to peak electric load.

Segment	Payback	Technical Potential (MW)	Percent of Technical Potential	Cumulative Percent of Potential
Turboexpanders	5.4	17	0.9%	0.9%
Oil sands mining	7.0	182	9.6%	10.5%
Sour gas plants	7.3	107	5.7%	16.2%
Refineries	7.6	104	5.5%	21.7%
Sweet gas plants	7.8	32	1.7%	23.4%
Petrochemicals	9.2	530	28.0%	51.3%
MSW	10.6	104	5.5%	56.8%
Kraft pulp mills	11.7	210	11.1%	67.9%
Oil sands in-situ	13.6	116	6.1%	74.1%
Education	20.0	29	1.5%	75.6%
Food industry	20.0	31	1.6%	77.2%
Saw, panelboard, CTMP	20.0	280	14.8%	92.0%
Gas flares	20.0	135	7.1%	99.1%
Hospitals	20.0	17	0.9%	100.0%
TOTAL		1893	100.0%	

Table 4-9. Payback and Percent of Technical Potential by Segment

Table 4-9 shows the segments in order of payback and illustrates the percent of technical potential represented by each segment for 1992. The last column in Table 4-9 shows the cumulative percent of potential. For example, the entry in this column for

the MSW segment indicates that 56.8% of technical potential has a payback less than or equal to 10.6 years.

In Figure 4-4, we show the percent of total technical potential with a payback less than or equal to the values on the horizontal axis. The points plotted as solid boxes represent the actual distribution of payback period across the various segments for the 1992 base case (i.e., the data from Table 4-9). We call this distribution the weighted payback distribution. This distribution captures the variation in payback among all segments and weights each payback number according to the segment's contribution to technical potential as was shown in Table 4-9.

The points plotted as solid boxes in Figure 4-4 capture cost variations among segments, but fail to capture cost variations within segments. If the variation of costs within segments is considered, there will be more exceptionally good and exceptionally bad projects and the points on the curve will be spread to the left and right. The effects of such variations within segments can be captured by increasing the variance of the weighted payback distribution.

In order to perform this analysis we fit a theoretical distribution to the actual weighted payback distribution. A lognormal distribution was used because it fits the data well, is analytically easy to use, and makes sense for payback numbers (which must be at least 0 but may be extremely high). The actual and fitted weighted payback distributions are shown in Figure 4-4, as solid boxes and a solid line respectively. Figure 4-4 also shows a distribution with the same mean payback but twice the variance of the actual distribution (the lighter line). To illustrate how the graph is to be interpreted, Figure 4-4 indicates that the actual percent of technical potential (in the 1992 base case analysis) with paybacks below 7.6 years is 21.7%, the approximation from the fitted curve is slightly lower at 16%, and the distribution with double the variance is slightly higher with 25% of technical potential at or below a 7.6 year payback.

Since the weighted payback distribution indicates what the payback period is for each fraction of technical potential, it can be used together with the payback acceptance distribution to calculate economic potential. For example, Table 4-9 indicates that 0.9% of technical potential has a payback of 5.4 years. A payback of 5.4 years implies acceptance by 16% of technically possible installations. Total technical

potential is 1893 MW, so the economic potential represented by this first 0.9% of technical potential is 1893 MW times 0.9% times 16% which equals 2.7 MW. This calculation can be repeated for each fraction of technical potential and each corresponding level of payback in order to calculate total economic potential.

The fitted distribution shown in Figure 4-4 works very well in reproducing the economic potential shown earlier for the 1992 scenario. To analyze the impact of variation within segments, the fitted distribution was altered by changing its variance but leaving its mean stationary. (Such a distribution with a variance twice that of the fitted distribution is shown in Figure 4-4.) Economic potential was calculated for distributions with variances that are various multiples of the base case variance. Results of this sensitivity analysis are shown graphically in Figure 4-5. The horizontal axis in Figure 4-5 shows the multiplier used to increase or decrease the variance from the fitted distribution. For example, a variance multiplier of 2 corresponds to the doubled variance curve in Figure 4-4.

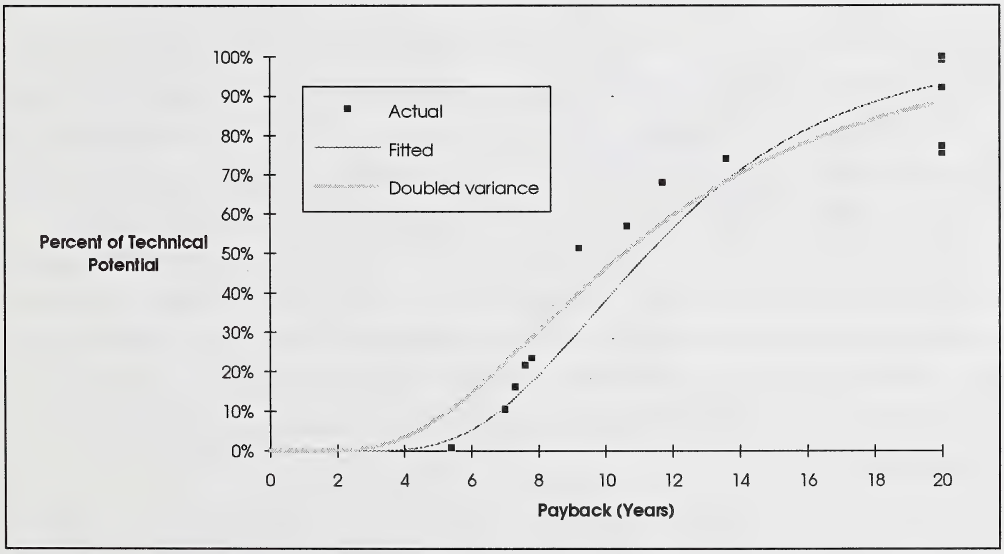

Figure 4-4. Weighted payback distribution - actual data and fitted curves

Figure 4-5. Sensitivity of 1992 economic potential to payback variance

The variation of costs within segments can significantly increase overall economic potential. Figure 4-5 illustrates that doubling the variance of the weighted payback distribution approximately doubles economic potential for the 1992 scenario. As seen in Figure 4-4, a doubling of variance does not constitute an unreasonably large shift in the weighted payback distribution. In fact, it seems reasonable to expect the inclusion of variance within segments to result in a doubling or tripling of variance across all segments. As a result, ignoring variance within segments could cause our base predictions to be a significant understatement of economic potential. In summary, the fact that some individual cogeneration and generation-from-waste developers are likely to face better economics than the typical facility in their segment may raise economic potential to 100 or 125 MW at present electric rates and sizing to peak electric load.

Alternative Payback Scenario

In the analyses presented to this point, an acceptance distribution based on survey responses was used to estimate economic potential. This distribution indicates that a 3 year payback is required for 50% of facilities in a segment to install cogeneration.

In this alternative scenario, a more favorable attitude towards cogeneration is assumed; 50% acceptance occurs at a 5 year payback. The payback to acceptance relationship is assumed to be linear, with 100% acceptance at a 0 year payback and 0% acceptance at a 10 year payback. All other parameters of the analysis are the same as in the 1992 base case. Figure 4-6 compares the two payback curves.

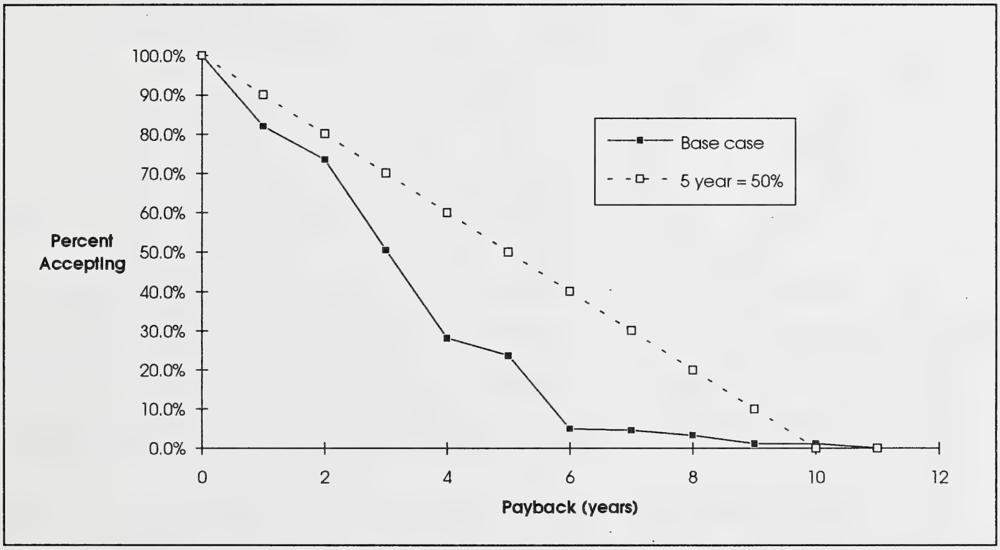

Figure 4-6. Base case and alternative payback acceptance curves

Total economic potential is illustrated as a function of electric rates in Figure 4-7 below for both of the payback acceptance scenarios.

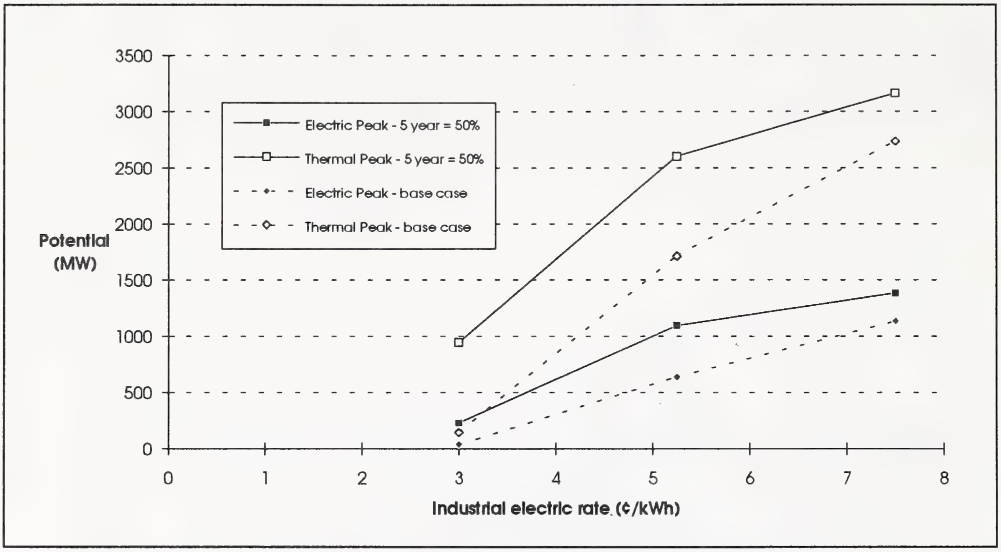

Figure 4-7. 1992 economic potential -
Base case and alternative payback acceptance curves

At an industrial electric rate of 3¢/kWh and sizing to electric peak, total economic potential is 168 MW in 1992 using the alternative acceptance curve. Tables 4-10 and 4-11 summarize the economic potential for all segments for the alternative scenario.

Economic Potential (MW)	Size to Peak Electric		
	Electric Rate		
Year	3¢/kWh	5.25¢/kWh	7.5¢/kWh
1992	168	945	1307
2005	9	1371	2276

Table 4-10. 1992 economic potential with alternate acceptance curve - electric peak

Economic Potential (MW)	Size to Peak Thermal		
	Buyback Rate		
Year	3¢/kWh	5.25¢/kWh	7.5¢/kWh
1992	711	2407	3085
2005	9	4004	5727

Table 4-11. 1992 economic potential with alternate acceptance curve - thermal peak

Table 4-12 compares the economic potential at the predicted industrial electric rate of 3¢/kWh for the 1992 and the 2005 scenarios and the two payback acceptance distributions.

Economic Potential (MW)	Size to peak electric		Size to peak thermal	
	Year		Year	
Scenario	1992	2005	1992	2005
Base Case	28	2	109	4
5 Year = 50%	168	9	711	9

Table 4-12. Comparison of economic potential - alternative payback acceptance curves

The payback acceptance curve used in the base case analysis represents a very high return, risk averse attitude towards investment in energy efficiency. For example, the three year payback period for 50% of decision makers to adopt represents a 33% internal rate of return. This corresponds to a risk premium of 18% to 23% over the cost of capital during the period the payback criteria was measured.[68] A partial explanation of this requirement for high returns may be found in the corporate level at which energy efficiency decisions are made. Some stakeholders have suggested that the required payback (or rate of return) is shorter (higher) for tactical investments made at a mid-

[68]This assumes that the cost of capital is approximately 3% over prime. The source for the prime rate is the *Statistical Abstract of the United States*, 1989, U.S. Department of Commerce.

management level than for strategic investments made at an upper management level. If cogeneration could be presented as a strategic decision to high-level decision makers, it may be considered with more favorable criteria resulting in higher levels of implementation.

Detailed analyses of the impacts of this scenario on each sector are provided in Appendix C in Tables C-9 through C-11.

4.2 Effect of Uncertainties on Sensitive Segments

Because of the nature of their costs or operations, certain segments may be particularly sensitive to some uncertainties. In this subsection, examples of sensitivities within individual segments are examined.

Sensitivity to Capital Cost in In-situ Oil Sands

Because of the high capital costs of the special high pressure steam equipment used in the in-situ oil sands cogeneration, this segment is likely to be particularly sensitive to capital costs. Sensitivity to capital cost is illustrated in Figure 4-8 for the in-situ oil sands segment.

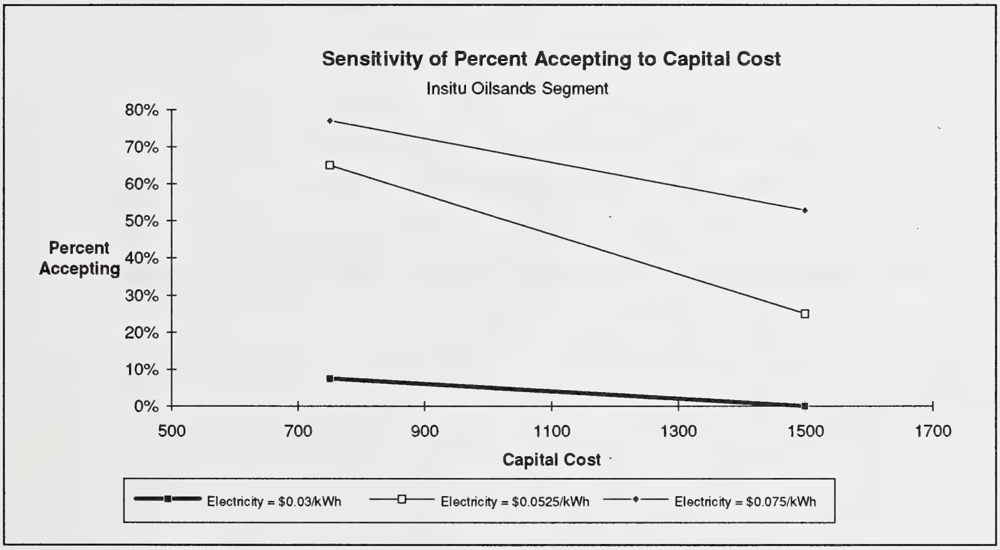

Figure 4-8. Sensitivity to capital cost - In-situ oil sands

The figure shows that without higher electric prices the economics of cogeneration in this segment are poor even with much lower capital costs.

Sensitivity to Maintenance Cost in Generation from Waste Segments

Because of the mixed and non-uniform nature of the fuel, all of the generation from waste segments are likely to face high and uncertain maintenance costs. The effects of increased maintenance costs were examined in the MSW segment. The results are shown in Figures 4-9 and 4-10 below.

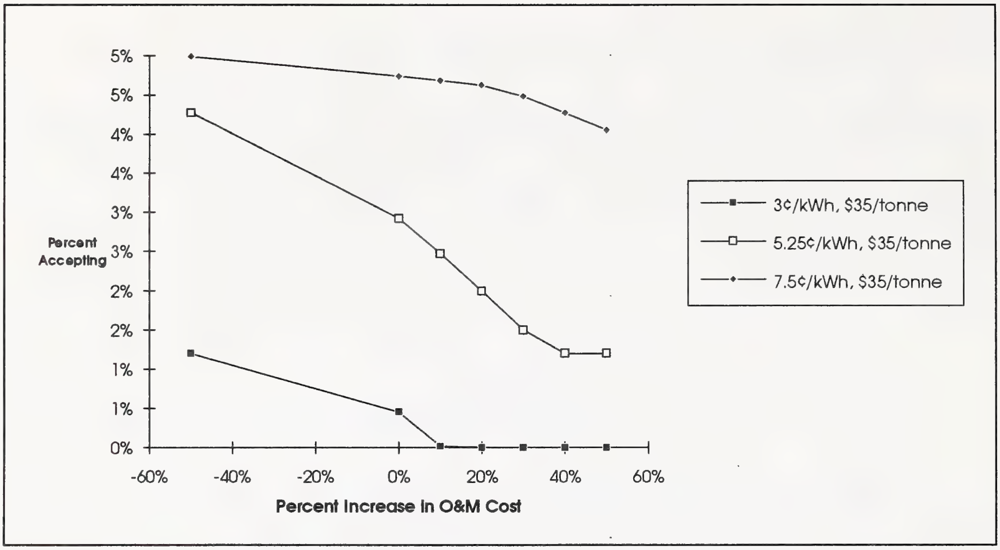

Figure 4-9. Sensitivity of percent accepting in MSW segment to maintenance cost - MSW tipping fee $35/tonne

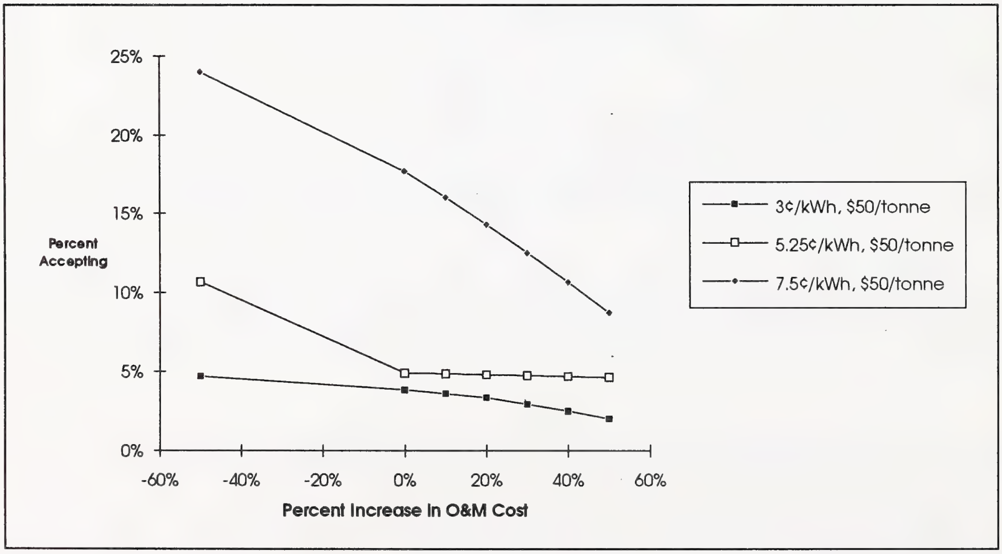

Figure 4-10. Sensitivity of percent accepting in MSW segment to maintenance cost - MSW tipping fee $50/tonne

In segments such as MSW where payback period is already quite long, there is little sensitivity to increased maintenance cost at present electric rates. At base case

buyback rates (3¢/kWh) and tipping fees ($35/tonne), payback increases from 10.6 years to 12.7 years with a 50% increase in maintenance cost. As a result, percent accepting decreases from 0.5% to 0%. At higher electric rates, for example 5.25¢/kWh or 7.5¢/kWh, potential is highly sensitive to maintenance costs.

Sensitivity to Economic Life in Sawmills, Pulp Mills, Petrochemicals

In situations where fuels may have harmful effects on equipment, equipment lives may vary significantly. These variations will not change the payback period but will change other measures of project economics, such as IRR. Sensitivity of IRR to economic life is illustrated in Figure 4-11 for some segments that may have particularly varied economic lives for projects. The results are shown for two levels of electric rate and are otherwise based on 1992 base case rates. In general, unless the change in project life is dramatic there is little impact on the IRR economic criterion.

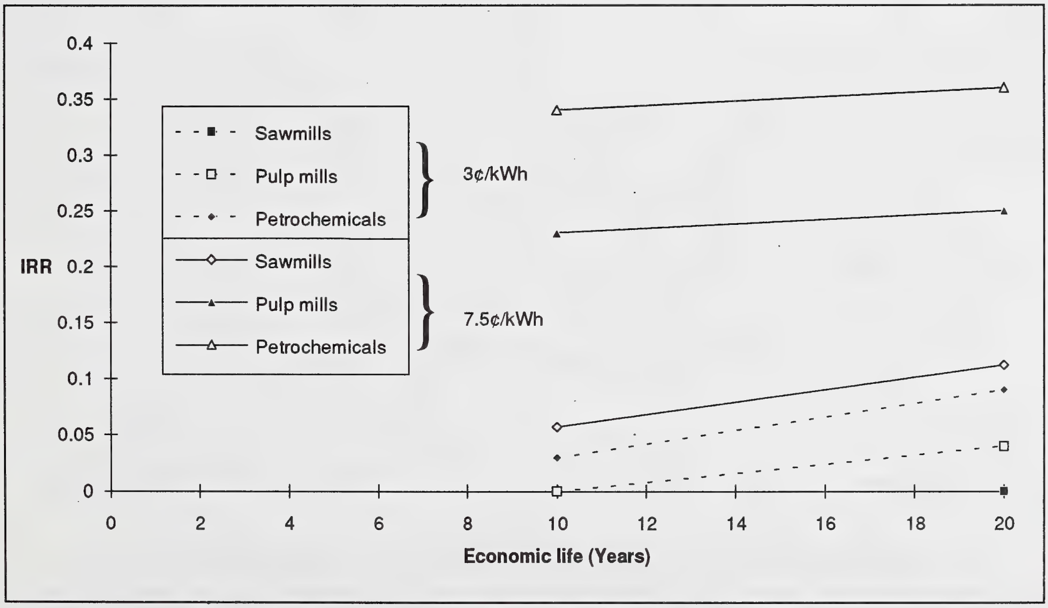

Figure 4-11. Sensitivity to economic life

Sensitivity to Interest Rate

Sensitivity of project economics to the real interest rate on project financing is illustrated in Figure 4-12 for two segments with relatively high capital costs: hospitals and in-situ oil sands, and one segment with normal capital costs, petrochemicals. The analysis illustrates that IRR is not highly sensitive to interest rates.

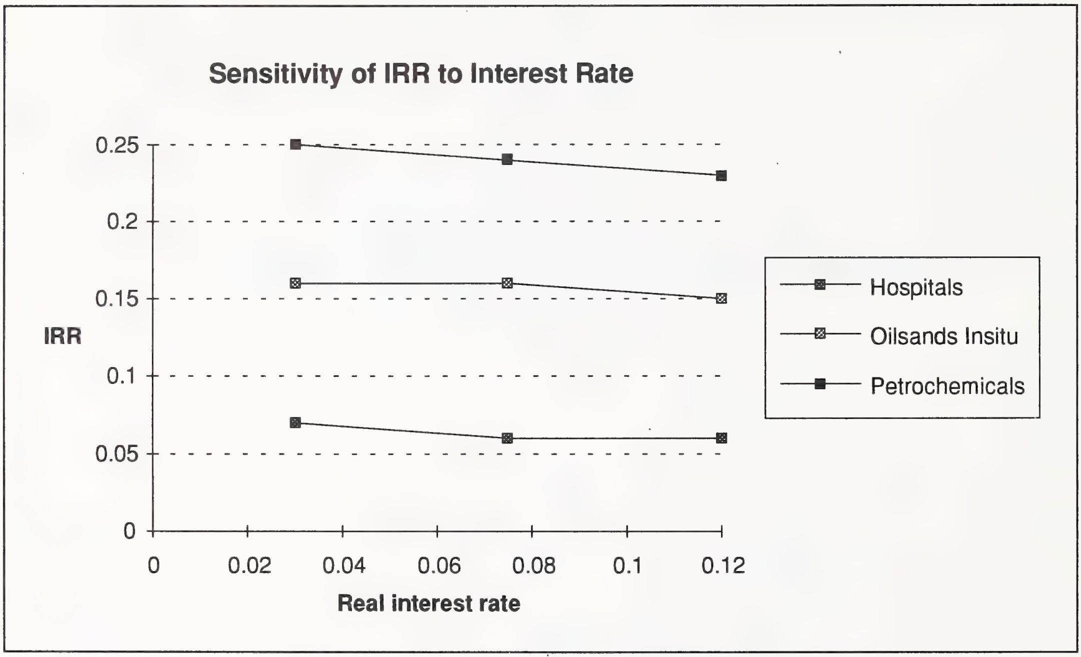

Figure 4-12. Sensitivity to interest rate

4.3 Penetration

The analyses presented in this report indicate long-run potential rather than short-run penetration. For example, this report assumes that 73.5% of industrial firms will implement a cost-effective energy investment with a two year payback. However, Alberta data show that less than 19% of firms accept such investments a year and a half after being informed of the investment opportunity.[69]

[69]Discussions with Alberta Energy, Electrical Policy Branch.

This discrepancy between potential and implementation is often characterized by a penetration curve which depicts the percentage of firms which accept a new technology (with respect to the total number of firms which will eventually accept the technology) as a function of the amount of time since the technology became available. A typical penetration curve is depicted in Figure 4-13.

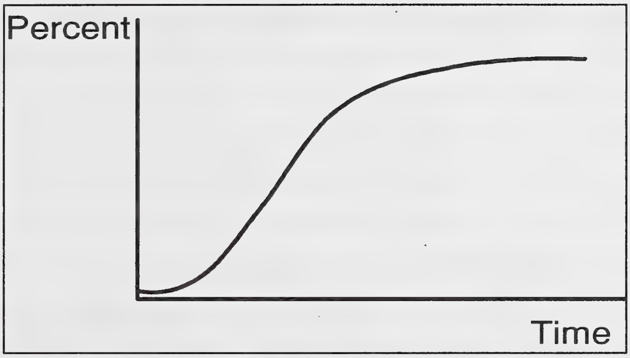

Figure 4-13. A penetration curve

The process of penetration is controlled by many factors including availability of information, equipment retirement patterns, anticipated changes in costs, changes in perceived risks, aversion to change, entry of new consumers, and production constraints. Complex models can be constructed that consider all these factors; however, most often penetration is predicted using simple S-curve models. Popular S-curve models are the complementary Gompertz and the logistic model. These models are scaled based on initial penetration rates, penetration rates of similar technologies, or subjective estimates of penetration. One analysis shows that for typical industrial innovations about 15 years is required to go from 10% to 85% of the ultimate market for the product.[70]

From the perspective of the individual making the investment decision, the penetration curve indicates a lack of knowledge about a possible investment and uncertainty about the return from the investment. There is a lag between when the technology becomes economically viable and when an individual decision-maker has enough information to be sufficiently confident that the technology will be economically viable to take the risk of investing in it. Thus, faced with an investment alternative with

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[70] *Patterns of Technological Innovation*, Devendra Sahal, Addison-Wesley, Advanced Book Program, Reading, Massachusetts, 1981.

very uncertain returns, an investment decision-maker will often choose to defer the investment decision until some of the uncertainties are resolved. Uncertainties in the returns from an investment in new technology typically decrease as implementation of the technology increases. That is, confidence in a technology accelerates as the technology is implemented in its target market. The concentration of cogeneration in only a few segments in Alberta (e.g., the wood and oil sands segments), while driven mainly by economics, is probably also influenced by the example of early implementers in these segments.

4.4 Summary

In this section sensitivities to a wide range of uncertainties have been examined. The major conclusion is that the electric retail and buyback rates remain the most critical variables in determining the level of cogeneration and generation from waste. At all levels of electric rates, almost all the other variables have large impacts on the level of generation if measured in percentage terms, but only at higher levels of electric rates do the variables have large absolute impacts. At the levels examined, gas costs, capital costs, and the payback criteria have similar impacts on the entire market. Maintenance costs may be important in the generation-from-waste sectors.

Variance in paybacks needs to be considered separately from the other variables examined in this section. For each of the other variables, we have chosen our best estimate, and we have no reason to believe that the actual value is likely to be higher or lower than the value assumed. However, because of the use of representative facilities to estimate segments, it may be possible that we have systematically understated the level of variance in the market. As a result, the base case may underestimate the potential for cogeneration and generation from waste.

5.0 Stakeholder Viewpoints

Between April 9 and 12, 1991 and again on May 8 and 9, 1991, Applied Decision Analysis and Synergic Resources Corporation met with diverse stakeholders concerned about the future of cogeneration and generation from waste in Alberta. During these meetings, informal and wide ranging discussions were held on the economic, technical, and institutional factors that will affect the development of cogeneration and generation from waste in Alberta. The discussion groups varied in size from one up to a dozen individuals. The Alberta discussions were supplemented with a number of telephone interviews with individuals that could not attend an in-person meeting. In total, 57 individuals representing 47 organizations were interviewed. These individuals are listed in Table 5-1.

There was a surprising degree of agreement in the opinions expressed by the diverse stakeholder groups. The next section presents a summary of the overall opinions. Following this are sections presenting the specific opinions of the individual stakeholder groups.

TABLE 5-1. INTERVIEW PARTICIPANTS

Commercial/Institutional
- Kevin Hanson, West Edmonton Mall
- Paul Lucas, Edmonton Northlands
- Ken Manning, Lethbridge General Hospital
- Pat McDonald, University of Alberta
- Dan Rozak, University of Alberta Hospital
- Mark Weisner, Edmonton Northlands

Electric Utilities
- Oliver Erdos, City of Lethbridge
- Stan Gent, Edmonton Power
- Gavin Hanslip, City of Calgary
- Michael Hogan, TransAlta Utilities
- Winston Kerr, City of Medicine Hat
- Bevan Laing, Alberta Power
- Frank Shinyei, Edmonton Power
- John Tapics, TransAlta Utilities
- Dick Way, TransAlta Utilities

Forest Industry
- John Isbister, AEC Forest Products
- Garry Leithead, Alberta Forest Products Association
- Robert McPhail, Alberta Newsprint
- Bob Olson, Weyerhauser Canada
- Alan Wahlstrom, Daishowa Canada

Gas Suppliers and Utilities
- Mike Hagan, Northwestern Utilities Ltd.
- Kasper Lund, Gulf Canada Resources
- Harry Maekelburger, Canadian Western Natural Gas Co. Ltd.
- Ron Man, Mobil Oil Canada
- Barry Peterson, Home Oil Company
- Doug Schmidt, Canada Northwest Energy
- Michael St. Clair, Canadian Hunter Marketing

Government
- Fred Homeniuk, ERCB
- Duane Pyear, Alberta Economic Development and Trade

NUGS/Equipment Suppliers
- Tony Howard, Monenco
- Collin Jackson, Energy Consulting Inc.
- Ross Keating, Canadian Hydro Developers

Fuels and Petrochemical Industry
- Jack Chan, Alberta Natural Gas
- Errol Dennison, Petro-Canada Resources
- R. Dufresne, Petro-Canada Resources
- Richard Gallant, Esso Resources Canada
- Hans Garritsen, Dow Chemical Canada
- Phil Hedderly, Syncrude Canada
- Stew Hunter, Coal Association of Canada
- Rick Kline, Unocal Canada
- Wilfred Lambo, TransCanada Pipelines
- Ron Lieberworth, Esso Resources Canada
- Larry McAlister, Novacor Chemicals
- Al McLarty, Milner/Fenerty
- Tracy Meyers, Chevron
- Olen Perry, Unocal Canada
- Dave Seysmith, Independent Petroleum Association
- Vic Sopkow, Novacor Chemicals
- Ron Steffan, Novacor Chemicals
- Don Towson, Petro-Canada Resources
- Brian Tyers, Amoco Canada Petroleum
- Ian Walter, Esso Resources Canada
- Ron Wendling, Canadian Fertilizers
- Frank Wong, Nova Corporation

Waste-to-Energy Proponents
- Art Irwin, Stanley & Associates
- Wilf Ouellette, St. Pierre Industries
- Mark Polet, Alberta Special Waste

5.1 Summary of Discussions

MOTIVATION

By far the most significant motivation for cogenerating or generating from waste is economics. The firms interviewed desire to reduce their total cost of energy or total cost of energy and waste disposal. After this major motivation, several firms noted that a desire to be "good citizens" and reduce environmental effects also encourages cogeneration and generation from waste. Some industries anticipate that future environmental regulations will significantly change their waste disposal costs. In these industries, social and economic motivations are hard to distinguish. In some remote locations, cogeneration is seen as a means of improving the reliability of the electric supply.

ECONOMIC ISSUES

A large number of factors determine the economics of cogeneration and generation from wastes. These are listed in Table 5-2.

Electricity is cheap. Throughout all the groups, the single most frequently noted factor that affects cogeneration and generation from waste potential in Alberta is the low cost of electric power in the province.

Uncertainty about the price of electricity is the second most frequently noted disincentive to project development. Installation of cogeneration or generation from waste is usually much less expensive at the initial construction of a host facility than as a retrofit. If uncertainty in future electricity prices prevents installation at initial construction, future prices that would justify initial installation may not justify a retrofit. Thus if developers are unwilling to speculate on future electric prices, the lack of a long term contracted price for sales to a utility may permanently lower the potential for cogeneration and generation from waste. A number of participants specifically stated that a firm price for electric sales to utilities, even if prices in the near term are low, would encourage them to invest in cogeneration or preparations for later cogeneration additions.

TABLE 5-2. FACTORS IN ECONOMIC ANALYSES

Electricity Rates
- Basic energy charge
- Basic demand charge
- Interruptible rates
- Buy-back rate for electricity sold to system
- Charges for maintenance power
- Charges for backup or standby power

Capital Costs
- Cogeneration and alternative equipment costs including environmental controls
- Interconnection costs

Operating and Maintenance Costs (cogeneration and alternative)

Fuel Cost
- Basic fuel cost
- Fuel transportation costs
- Fuel preparation costs
- Fuel storage costs

Financing Cost
- Interest
- Fees

Taxes and Incentives
- Income taxes
- Property taxes
- Royalties on fuels
- Economic development incentives
- Small business incentives

Waste disposal cost

Depreciation

Insurance

Inflation

Most participants did not consider it difficult to estimate the capital, operating, or maintenance costs of facilities. The exception is in some generation from waste technologies. Many of these technologies are relatively new, and it is uncertain how waste fuels may affect equipment life and maintenance. One utility respondent said that most developers of cogeneration under estimate maintenance costs.

Uncertainty about gas prices also discourages cogeneration development. Some respondents, particularly developers of cogeneration projects that are highly dependent on gas price (such as greenhouses) and gas marketers, would like to see electric buy-back rates tied to the price of gas; this would remove both the buy-back rate and the fuel cost uncertainty. Developers of highly gas dependent projects are also interested in long term gas contracts (20 years).

Other respondents noted that all gas cogeneration operations are not equally sensitive to gas price. For example a hospital laundry will be buying gas for steam whatever it costs, and the hospital will only worry about the incremental increases in gas purchases due to cogeneration.

Estimating net fuel costs for generation from waste is difficult. The future costs of alternative waste disposal, tipping fees and incineration costs are uncertain. Also, the quality of waste fuel and, therefore, the cost per unit of heat can vary significantly creating both economic and technical problems. Further, transportation and preparation costs for waste fuels can often be high.

Estimation of financing costs did not seem to be a major issue.

Taxes and incentives can have a major impact on a project's viability and can be complex. For many projects it seems uncertain what tax and depreciation rates should be used; particularly confusing are CCA tax rates and depreciation under Class 34 regulations. The special depreciation treatment under Class 34 is important to many projects.

The benefits of cogeneration and generation from waste are identified through life cycle costing that balances early capital costs with long-run operating savings. A problem for many potential cogeneration and generation from waste developers is the separation of capital and operations budgets. This occurs in all economic sectors,

including government, industrial, and commercial; but may be most prevalent in the commercial sector where developers own buildings for only a limited period.

A final economic and technical problem is that the minute-to-minute availability of cogenerated electricity is generally dependent on schedules determined by the host process and not the electric system's need for electricity. Thus cogeneration will often displace very low cost resources or be unavailable at times of peak demand. This means that cogeneration must be base loaded, and it reduces cogeneration's value as an electric system resource.

TECHNICAL ISSUES

The respondents identified only a few technical issues.

Generation from wastes faces special technical problems. Many of the technologies are new, and their operating characteristics are unfamiliar. The quality of wastes as fuels is a special problem. Both wood wastes and municipal refuse vary significantly in quality. Pollution from waste burning is a critical issue, with the release of toxics being a special concern.

Location is likely to be an important factor in encouraging cogeneration. Several participants suggested that cogeneration will first appear in areas on the fringe of the Alberta electric system, where reliability is low and the cost of transmission development is high.

REGULATORY ISSUES

The most discussed regulatory issues are how the prices paid to new electric suppliers should be set and how new increments of supply should be approved. With a very few exceptions potential cogenerators did not want to come under rate regulation and prudence review as faced by utilities. Cogenerators and generators using wastes are not willing to accept the uncertainty in rates that they perceive in the present utility rate setting process.

Two processes were almost equally favored for setting rates paid to cogenerators and generators from waste that supply the system:

- Firm rates based on avoided costs and set in public hearings. A number of individuals felt that the rates should recognize environmental costs and reliability of supply. Most but not all potential generators wanted rates set over a period long enough to provide for recovery of costs.

- Bidding for new generation. It was emphasized that the bid process had to be set up fairly. For example, all parties should have sufficient notice of bidding periods to develop project plans. It was also noted that the bidding process should consider the stability of the host, the ability to be dispatched, reliability, and local system requirements.

Gas suppliers and cogeneration developers were very much in favor of considering environmental costs; other participants were mildly supportive of this idea. Utilities strongly supported considerations of reliability, and large industrials generally supported this view. Utilities expressed concern that, if rates are leveled over periods of low and high avoided cost and if both generation costs and avoided costs grow over time, some cogenerators might have an incentive to leave the system just as their power is needed.

Environmental legislation seems to be the next most important area of regulation for cogeneration and generation from waste. The possibility of environmental costs being considered in the evaluation of new generation was mentioned above. Regulations that might limit the use of coal would also provide new opportunities for cogeneration. Waste generation may be limited by emissions' constraints or greatly encouraged by limits on other methods of waste disposal. For example, limits on conventional methods of burning wood wastes are a critical factor in the forest industry's present interest in generation from waste.

Natural gas regulation was also a topic of discussion. Most of the participants believe that there is a policy against using natural gas in base load generation. One respondent stated that recent discussions with Alberta Department of Energy officials confirmed that coal was the fuel of choice for base load generation. Issues regarding royalties on natural gas were also raised. The two major questions were:

- What will be the royalty treatment of waste gas used for generation?

- What is the royalty treatment of gas used jointly in cogeneration and heavy oil production?

More minor regulatory roadblocks include regulations against natural gas engines in buildings and regulations requiring manning by steam engineers.

Although no specific regulatory barriers were mentioned, many participants felt that utilities are restricted in their participation in cogeneration. There was also concern that utilities are restricted from supporting innovative technologies.

Gas marketers and utilities felt that active promotion of electric energy exports from the province would be a positive development.

OTHER ISSUES

A number of other roadblocks to the development of cogeneration and generation from waste were mentioned. These include:

- Demand charges are relatively high in Alberta. Therefore, customers can achieve significant reductions in energy charges through peak shaving or interruptible rates. This can reduce cogeneration cost savings. Because of the significant over capacity in the system; the need for high demand charges is unclear.

- Utilities are perceived to be indifferent or negative towards cogeneration.

- Banks are perceived to concentrate on large projects, $10,000,000 and up.

- Developers are perceived as only doing "best-case" analysis.

- Some participants felt that the oil industry expects excessively short pay backs, such as three years.

- Participants noted that cogeneration must compete with conservation, peak shaving and other energy efficiency improvements.

POTENTIAL GENERATION SOURCES

Table 5-3 presents a list of sources for generation from waste and cogeneration that were mentioned during the discussions. The list identifies locations or firms at which the source of generation is being used or has been studied.

TABLE 5-3. POTENTIAL GENERATION SOURCES

Generation from Waste or Uneconomic Fuels

- Common commercial and institutional wastes (May be used to replace electricity with absorption cooling rather than to generate.) -- University of Alberta
- Infectious hospital wastes
- Toxic waste incineration -- Swan Hills
- Methane gas from land fills and sewer gas -- City of Lethbridge, Calgary, Edmonton
- Shut-in natural gas
- Flare gas -- Unocal, Esso, Amoco, TransAlta
- Municipal waste
- Coke from oil sands production -- Syncrude
- Peat -- St. Pierre Industries
- Paper and pulp - Millar Western, MARMAC, Weyerhauser

Cogeneration Potential

- Turbo expanders -- Monenco
- Greenhouses -- Energy Consulting Inc. and City of Medicine Hat
- Waste heat at compressor stations -- NOVA, TransCanada
- Heavy oil development -- Shell and Esso
- Oil sands -- Esso
- Upgraders -- Esso
- Hospitals -- Lethbridge
- District heating -- Edmonton
- Institutions -- City of Medicine Hat
- Commercial buildings
- Gas plants
  - Sour
  - Sweet
- Petrochemical and Chemical
  - Magnesium
  - Chlorine
  - Caustic soda
  - Ethylene
  - Ammonia -- City of Medicine Hat
  - Carbon black -- City of Medicine Hat
- Refineries
- Breweries
- Cement kilns

5.2 REVIEW OF STAKEHOLDER GROUPS

COMMERCIAL/INSTITUTIONAL

Economics

Financial issues that are of particular concern in the commercial industrial sector include:

- For many commercial buildings, the developer does not hold the building for a long period; therefore, developers are reluctant to increase capital costs in exchange for savings in operations. This may also be true for public and other buildings when the capital and operating budgets are strictly separated.

- For large institutions -- including hospitals, universities, arenas, malls -- waste disposal through incineration is attractive; therefore, tipping costs are important for this segment. Generation from waste may compete economically with the use of heat directly for heating, absorption cooling, and other uses.

- Regional incineration for hospitals may improve the economics for generation from wastes.

- Similarly regional laundry may improve the ability to cogenerate (Foothills Hospital in Calgary).

Net present value (NPV) and pay back are both used for project evaluation in this sector. A five year pay back is considered good; provincial government generally requires a 7 to 8 year period.

Technical

Location presents special problems for urban generation and/or incineration projects. The urban setting can create problems with regard to visual aesthetics, noise, traffic, and perceived pollution risks.

One respondent emphasized the very high steam and heat needs of hospitals and universities, and suggested that these facilities, particularly with summer absorption cooling, are excellent candidates for cogeneration.

Institutional

Commercial sector participants promoted a stronger government role in providing information on cogeneration and encouraging communication among cogenerators and potential cogenerators. Public promotion of cogeneration would also help urban generators convince the public of the value of these projects. Some commercial sector participants would like see outside developers provide financing, construction, and operation with the host operations being isolated financially from the project, except for reductions in energy costs.

Decision Making

A move toward cogeneration or generation from waste is usually initiated by a technical person. Funding must often be applied for from provincial sources for public institutions.

ELECTRIC UTILITIES

Economics

Utilities must divide both fixed and variable costs between heat and electric production because of rate-of-return regulation on the electric production. Exact rules for allocations are unclear.

The utilities use internal rate of return (IRR) and NPV of revenue requirements in evaluating investments. They may also examine pay back, and a figure of 3-4 years as a payback rate was mentioned.

The utilities realize that dispersed generation may in some cases reduce transmission costs by creating an electric supply closer to a load. One utility noted that

cogeneration and generation from waste must compete not only with the present use of energy but with alternative projects such as conservation and peak shaving. The respondent emphasized that optimum energy efficiency for the customer should be the goal.

Technical

The utilities are concerned about the long term reliability of cogenerators (cogenerators going out of business) and short term reliability and power quality. The utilities feel that predictable and clean power from cogenerators is a necessity.

Institutional

The utilities are comfortable with the present regulatory system with respect to cogeneration. It was emphasized that in any procedure for setting rates reliability had to be considered. Two of the utilities indicated that inclusion of environmental benefits and costs in avoided cost calculations would be seen as appropriate.

One utility suggested that investments made now to preserve the option of installing cogeneration at a later date, i.e., investments to reduce retrofit costs, should be allowed in rate base as prudent investments.

Future

In the future there will be a mix of sources including many non-traditional, short lead time, and low capital cost sources such as cogeneration. It was felt that cogeneration will occur without subsidies or special programs. The rate and level of cogeneration development will depend on any environmental restrictions placed on coal.

One utility emphasized that it would remain the utilities' responsibility to supply the bulk of the electricity needs in the province, "the fundamental energy supply."

FOREST INDUSTRY

Economics

The special economic issue in the forest industry is the increasing cost of waste disposal. The Teepee burner, the standard method of wood-waste disposal, is no longer an option because of environmental regulation. Environmentally safe disposal of mill sludge is also becoming more expensive.

Technical

Mill sludge and other wood wastes appear to have promise as a fuel for generation, but there are a number of problems. These include environmental problems such as particulate emissions and ash disposal and a number of fuel problems. The quality and quantity of the fuel available can vary widely, and transportation and storage costs for fuel can be high.

Institutional

The chief institutional concern of the forest industry is coordination between environmental and energy regulators. They would like to see some credit given to energy from waste for its expected positive effects on the environment.

FUELS AND PETROCHEMICAL INDUSTRY

Economics

For almost all these large companies, capital for cogeneration projects will come through the corporation, and the project will be evaluated by the corporation's standard financial measures.

Most of these firms use IRR or NPV criteria for evaluating projects. The nominal cost of capital is as high as 20%. Twenty percent nominal seems to be a typical NPV discount rate or IRR hurdle rate. Some oil companies were reported to require very high rates of return and pay backs as short as 3 years.

Technical

Respondents expressed concern about additional environmental problems with some forms of cogeneration.

Institutional

Attitudes towards regulation and government policy were similar to other groups. They emphasized that the least expensive source should be developed. In general, these firms worry more about their rate for electricity than profits from cogenerating.

Open wheeling was very popular in this group. It is seen as a way of making the electric market more competitive and assuring that market prices reflect the underlying economics of electric production.

There was some division of opinion but most would like to see the utilities get more involved in cogeneration. Many industrials don't want to be in the electric utility business and are uncomfortable with involvement in a regulated industry. Many of them felt that utilities were reluctant to get involved with projects due to regulatory constraints, though specific constraints were not mentioned. Those concerned about utility involvement in cogeneration were uncomfortable about a utility having control of a vital part of their operations.

Decision Making

Ideas for projects usually originate with the technical people. About half the participants would use outside consultants to help evaluate a project. Project reviews usually take months, and project timing will be based on the need for heat not the electricity generation. Corporate interest is usually low because of cheap electricity. Corporate environmental concerns can gain attention and help get cogeneration projects approved.

Future

Opinions varied on the future of cogeneration and generation from waste; estimated impacts ranged from 20% to 80% of new supply. The opinion was expressed that only extremely efficient cogeneration will be installed between now and the later third of the decade.

GAS SUPPLIERS

Institutional

Gas suppliers were among the strongest advocates of cogeneration. They favored a number of changes in regulation and policy. These include:

- Exports of electricity should be encouraged.
- It should be clearly stated that there is no policy against the use of gas in base load generation.
- Environmental factors should be considered when evaluating sources for electricity.
- Gas royalties should not be applied to cogeneration uses.

This group felt that the study should be expanded to examine the benefits of gas generation as a central topic.

GOVERNMENT

Economics

The opinion was expressed that cogeneration should not be developed unless it is economically competitive with other electric sources. Consideration of environmental costs in evaluating new electric resources is fine; but if environmental costs are only

considered in the electric industry, unexpected distortions in the economy as a whole could occur.

Institutional

It was stated that natural gas policy is not a barrier to cogeneration.

NUGS/EQUIPMENT SUPPLIERS

Economics

Developers believe that cogeneration offers environmental advantages; increases system reliability by spreading outage risks over many dispersed, independent units; and can track load growth better. These advantages need to be considered when comparing generation alternatives. Developers would like to see "least cost planning." They do not feel that open wheeling would be a big advantage. They were not positive toward rate basing because of prudence review nor were they enthusiastic about bidding.

Pay back period and IRR are the major evaluation criteria for these projects. Typical pay back criteria is 5-7 years and IRR is 20%.

Institutional

One developer said that banks and other financial institutions are generally positive toward cogeneration projects; however, they favor larger projects, $10,000,000 and up, and require an experienced developer.

Utilities are seen as having a pro coal, pro big generation orientation by this group.

Future

Views about the future varied from 200 MW of cogeneration and generation from waste between now and 2000 with the bulk coming from pulp and paper to all new generation being cogeneration or generation from waste.

WASTE TO ENERGY PROPONENTS

Economics

Generation from wastes must compete with recycling for prime fuels such as paper and cardboard.

Future

These respondents believed that cogeneration will first appear in areas that need power because of transmission shortages, and that most new power in this century will be cogeneration or generation from waste. The biggest waste sources will be wood waste and municipal refuse.

6.0 Policy Implications and Conclusions

The most discussed policy issues are how the prices paid to new electric suppliers should be set and how new increments of supply should be approved. With a very few exceptions potential cogenerators did not want to come under rate regulation and prudence review as faced by utilities. Cogenerators and generators using wastes are not willing to accept the uncertainty in rates that they perceive in the present utility rate setting process. Other important policy issues include:

- Future impacts of environmental legislation
- Structure of electric rates
- Gas royalties policy
- Export policy

6.1 Pricing Approaches

Three pricing approaches are possible: rate basing, avoided costs set in public hearings, and bidding.

Rate Basing

Rate basing is satisfactory to utilities and government, but not liked by other stakeholders. It is difficult to determine the proper allocation of costs to thermal and electric energy, and this approach places the allocation of risk from excess capacity in the hands of regulators. When excess capacity situations occur, costs are either born by rate payers or transferred to the developer through cost disallowances.

Avoided cost set in public hearings

This approach is popular among many stakeholders. However, it may be difficult to define avoided costs that efficiently account for dispatchability. (Units that are used only to peak may have much higher value to the electric system than units that supply base load. This issue is discussed in more detail later.) This approach transfers the risk of over capacity to rate payers, if prices and purchases are guaranteed.

Bidding

This approach is also popular among many stakeholders, and it would allow regulators or utilities to define multiple bid evaluation criteria that consider issues such as dispatchability. Bidding would be a new process for Alberta, and this approach transfers the risks to rate payers, if prices and purchases are guaranteed.

6.2 Environmental Issues

Environmental legislation seems to be the next most important area of regulation for cogeneration and generation from waste. Gas suppliers and cogeneration developers were very much in favor of considering the environmental costs of generation; other stakeholders were mildly supportive of this idea. In the analysis of the environmental scenario, it was shown that regulations that might limit the use of coal and increase the cost of present electricity supplies would provide significant new opportunities for cogeneration. Waste generation may be limited by emissions' constraints or greatly encouraged by limits on other methods of waste disposal. For example, limits on conventional methods of burning wood wastes are a critical factor in the forest industry's present interest in generation from waste. Our analysis suggests that while important for individual segments, costs of disposal can be very high without having a large impact on the overall cogeneration potential.

6.3 Value of Peak versus Base Load

As noted earlier, policies towards peak and base load units may be quite important. Peak and base load should not be equivalently valued for economical operations. In systems with peaking capacity constraints, the differences in value between peaking and baseload plants can be dramatic. The value of electricity at peak periods is driven up by the use of more expensive generation and by the cost assigned to the risk of system failure when the system's capacity is strained. Simple, levelized avoided costs may not recognize the value of matching supply availability to demand. Techniques for pricing that help match the value of the supply and payments made to suppliers include: time-of-supply payments, spot pricing, or contracts with premiums for dispatchable supply.

Tables 6-1 through 6-3 illustrate the economic loss resulting from purchasing low cost base load cogeneration rather than a higher cost peaking plant. Table 6-1 specifies the marginal electric cost over a year for a simple electric system. The most expensive 100 hours might correspond to production from very high cost units or emergency purchase from neighboring utilities. Table 6-2 illustrates an economic analysis of adding a new peaking plant to cover the 2100 most expensive hours on the system. The levelized cost of the peaking plant is $.068/kWh. Table 6-3 illustrates that baseload would be inefficient for this system at anywhere near this levelized cost. It shows an economic analysis of adding baseload plant providing the same amount of energy as the peaking plant of Table 6-2. If a price of $.06/kWh is paid for this baseload, the loss is $1111/kW.

Costs of present system during one year:	
100 hours at	$0.50/kWh
2000 hours at	$0.05/kWh
6660 hours at	$0.01/kWh
Average cost:	**$0.025/kWh**

Table 6-1. Electricity cost for simple electric system

Output from this plant is distributed to each price period in proportion to the hours at that price. It is assumed that a lower cost plant is dispatched prior to higher cost plants, and thus new lower cost plants result in the displacement of the highest cost supply. (The highest cost supply is pushed off the top of the stack.)

Economics of peaking plant operating at 2100 kWh/yr for 15 years:

Plant specifications: Capital cost = $1200/kW, Operating cost = $0.03/kWh, Lifetime = 15 years.

	Cost of plant over 15 years:		Cost of replaced power:	
Operating:	15 x 2100 x $0.03	945	15 x 100 x $0.50	750
Capital:		<u>1200</u>	15 x 2000 x $0.05	<u>1500</u>
Total:		2145		2250
Savings:	$2250 - $2145 =	$105/kW		
Levelized cost:		$0.068/kWh		

Table 6-2. Economics of peaking plant

Economics of purchasing 2100 kWh/year of base load at $0.06/kWh for 15 years:

Plant specifications: Capital cost = $1200/kW, Operating cost = $0.03/kWh, Lifetime = 15 years.

	Cost of baseload		Cost of replaced power:	
	15 x 2100 x $0.06	1890	15 x (100/8760) x 2100 x $0.50	180
			15 x (2000/8760) x 2100 x $0.05	359
			15 x (6660/8760) x 2100 x $0.01	<u>240</u>
			Total:	779
Loss:	$1890 - $779 =	$1111/kW		

Table 6-3. Economics of base load plant

6.4 Potential Cost of Backup Power

The analysis in this subsection illustrates that the development of cogeneration in most segments will require reasonably priced backup power. Currently, the cost of backup power for cogenerators is approximately $3.60/kW per month, which equates to about $0.0058/kWh for a cogenerator operating 85% of the time.

Operating without backup power will usually be prohibitively expensive. For most industrial customers the cost per lost kWh is $9.00 to $26.05.[71]

Payment of capacity charges during down periods (rather than backup power charges) would likely be much more expensive than current backup charges though less expensive than going without backup. In Figure 6-4, the cost of backup power is related to the cost of a backup event and the frequency of these events. For example, if backup is needed on average every 6 weeks, capacity charges are $15.00/kW, and the load factor is 85%, backup costs will add $0.012/kWh to the cost of electricity.

Because the need for backup due to maintenance or equipment failure will have very little correlation with system peak loads, it will usually not be economically efficient to charge full capacity charges for backup or standby power.

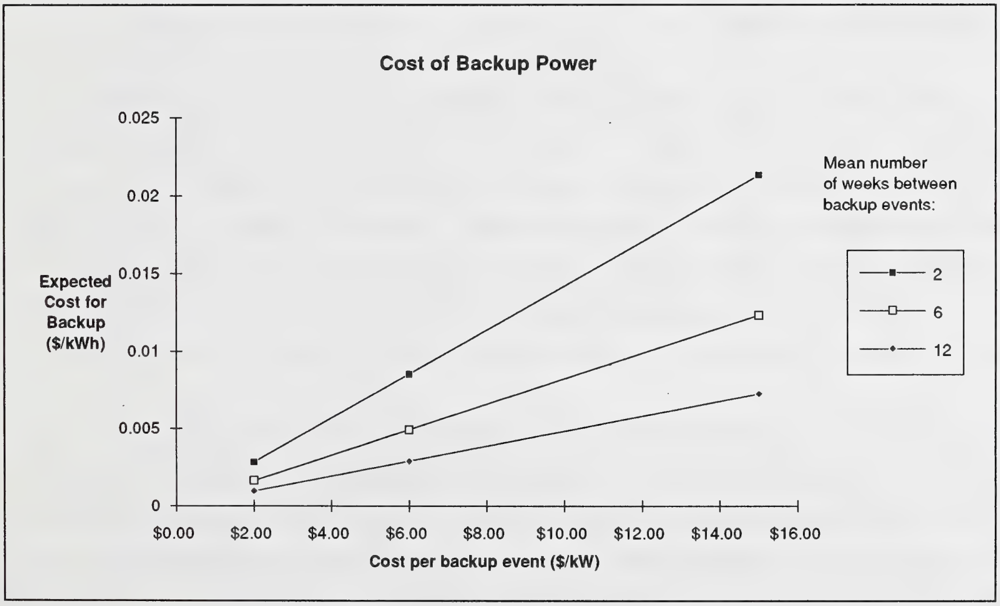

Figure 6-1. Cost of backup power

[71]Customer Demand for Service Reliability, A synthesis of the Outage Costs Literature, EPRI, Report P-6510, EPRI, Palo Alto, California, September 1989.

6.5 Gas Royalties Policy

In the flare gas, oil sands, and gas processing segments gas royalties policy is important. Specifically, potential cogenerators are concerned about the following issues:

- What will be the royalty treatment of waste gas used for generation?

- What is and will be the royalty treatment of gas used jointly in cogeneration and heavy oil or other energy production?

The analysis of flare gas shows that even without royalties there is very little potential for flare gas based generation. Traditional royalty treatment would reduce this potential still further.

6.6 Other Policy Issues

Low electric rates are clearly the largest discouragement to cogeneration and generation from waste in Alberta. However, a government policy to increase rates as an encouragement to cogeneration would not be economically efficient. As noted earlier, government policies in other areas, such as the environment, may raise rates for conventional generation and thus encourage cogeneration. Rate setting might also consider other advantages of cogeneration such as increased reliability through more diverse units and reductions in transmission costs through widely dispersed units.

A second major reason for the lack of cogeneration and generation from waste is the very short payback periods required for these projects. Our discussions with stakeholders suggest three reasons for this requirement of extremely high returns: risks associated with novel projects, decision making at mid-management levels, and higher returns required of projects out of the main line of business. The major risks that government policy could reduce, are the risks associated with electricity price and the stability of the market. If electric sales and gas prices could be firmly contracted for the long term, project financing risks would be drastically reduced. Perceived risks associated with project operations may be more difficult to reduce. Traditional approaches to reducing these risks have been through demonstration, education, and promotion. In addition to reducing perceived risks, government promotion of

cogeneration might also move the decision to cogenerate higher up the corporate ladder and thus reduce the requirements for returns on such projects.

Policies should also be examined that may be currently discouraging the development of cogeneration. Stakeholders, at the time this study, were uncertain about government fuel policy and many felt that government policy was against the use of gas for electric generation. Because neighboring areas have higher electric rates than Alberta, discouragement of energy exports may retard the growth of cogeneration. Finally, lack of access to internal transmission may discourage some cogeneration projects that would wheel surplus electricity inside Alberta. Such wheeling might occur between units of the same firm or between firms.

Other policy issues are very diverse and are not individually dealt with in detail here. They include:

- For utility based generation, regulatory policies on the division of cost between electric and thermal loads may be critical. This division will affect evaluation of the desirability of the electric source and the ability to sell the thermal source.

- For urban based generation (district heating and cooling, generation from waste, many commercial projects), siting problems may be significant. Government approval of projects and promotion of projects to the public may be very important.

- Presently most cogeneration is being developed by large host firms with significant financial resources. If smaller, independent developers are to play a larger role some support may be required, such as informing financiers of the risks involved with IPP.

6.7 Conclusions

This study shows there to be very little potential for cogeneration and generation from waste in Alberta under current rates and policies. The sensitivity analyses illustrate several ways in which the base case predictions could understate future

potential. For example, potential is increased in a scenario with significant variation within segments and in a scenario which considers the impact of stricter environmental controls. However, these alternative scenarios do not typically increase economic potential significantly above current implementation. Furthermore, economic potential overstates expected implementation at least in the near term as it does not consider penetration over time.

Significant increases in cogeneration implementation appear to require significant changes in policy. A number of policy tools have been identified which can potentially be used to increase implementation of cogeneration. The tables in this report are designed to allow a general analysis of the impacts of various types of policies. However, it is recommended that any specific proposals for significant policy change be investigated individually and in greater detail than is possible in this report.

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Appendix A

Consumer Profile

INDUSTRY
CONSUMER PROFILE

"COGENERATION AND WASTE ENERGY GENERATION POLICY STUDY"

Prepared by:
Alberta Department of Energy
March 16, 1992

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CONSUMER PROFILE - MARCH 16, 1992

SUMMARY TABLE: ELECTRICITY CONSUMPTION - ALL SECTORS (1990)

EUPC Segment	Total Customers [1]	Large Cust. (> 2 MW)	Purchases Large Cust. (MWh)	Purchases All Cust. (MWh)	Capacity Onsite (MW)	Generation Onsite (MWh)
Oilsands Insitu	39	6	609,515	671,755		
Oilsands Mining [2]	23	3	166,429	392,036	333.0	1,585,700
Oilfield	21,245	16	693,872	2,940,949		
Gas Plants/Compressors	781	58	3,808,015	4,813,300	34.3	26,300
Refineries/Bulk fuel outlets [3]	18	5	999,944	1,023,792	6.9	21,000
Petrochemical/Chemical	32	19	2,702,798	2,727,883	207.6	1,377,600
Forestry [4]	57	13	954,713	1,035,343	122.0	629,000
Cement/Concrete [5]	73	2	NA	259,630		
Coal	5	5	276,504	276,504		
Company Use	7	4	185,894	203,808	1.2	
Food Processing/Breweries	367	14	219,738	505,557	6.3	11,500
Metals, Mining, Other Ind. [6]	3,352	28	726,215	1,415,162	1.6	6,500
Total Industrial	25,999	173	NA	16,265,719	712.9	3,657,600
Large Educational		10	488,714		4.8	N/A
Hospitals/Health facilities	257	13	296,285		22.9	31,800
Other Commercial		138	1,948,101		5.9	600
Total Commercial	107,558	161	2,733,099	10,309,163	33.6	32,400
Other Miscellaneous	106,774	0	0	2,914,150	2.3	
Residential	825,875	0	0	5,929,546		
Totals	1,066,463	334		35,418,578	748.8	3,690,000

SOURCE: Energy Resources Conservation Board, Alberta electric utilities

[1] Total number of customers as per utility billing category.

[2] Total oilsands mining projects: 2

[3] Total refineries: 6

[4] Total number of sawmills is in excess of 200 of which the majority are very small.

[5] Total cement plants: 2 (Lafarge - Exshaw, Inland - Edmonton)

[6] Primary metal industries in Alberta:
- Sherritt Gordon Nickel/Cobalt refinery - Ft. Saskatchewan
- Magcan - High River (shut down in 1991)
- Stelco - steel works, Edmonton; pipe works, Camrose
- IPSCO - steel works, Calgary; pipe works, Red Deer, Edmonton, Calgary, Brooks
- Prudential Steel - pipe works, Calgary

SUMMARY TABLE: NATURAL GAS CONSUMPTION - ALL SECTORS (1990)

EUPC Segment	Total Customers [7]	Large Customers (above 50 TJ)	Gas Consumption Large Customers (GJ)	Total Gas Consumption (GJ)
Oilsands Insitu	9			62,586,000 [8]
Oilsands Mining	2		24,358,190 54,382,928	24,358,190 [9] 34,382,928 [10]
Oilfield	44	1	N/A	195,675 [11]
Gas Plants [12]	636		N/A	96,209,102 [13]
Refineries [14]	47	10	27,328,486	27,761,628
Petrochemical/Chemical	81	21	145,923,618	146,064,876
Forestry	235	15	5,231,810	5,556,964
Cement/concrete [15]	138	7	6,990,103	7,465,267
Coal	1	1	N/A	N/A
Company Use [16]	12	10	28,804,235	29,299,855
Food Processing/Breweries	235	26	5,852,856	7,276,969
Metals, Mining, Other Ind.	2,107	29	5,814,427	11,156,817
Total Industrial	3,547			452,314,271
Large Educational	1,161	16	4,294,509	9,555,240
Hospitals/Health facilities	1007	23	4,014,675	6,298,240
Other Commercial	58374	66	5,913,606	77,222,062
Total Commercial	60542	105	14,222,790	93,075,542
Residential	630,729	0	0	99,045,902
Totals	694,818			644,435,712

SOURCE: Energy Resources Conservation Board, Alberta gas utilities, Industry data bases

[7] Total number of customers as per utility billing category

[8] Based on the ERCB figure of 1,647,000 E3m3 of fuel gas consumed in 1990 for ail insitu projects

[9] Based on the ERCB figure of 641,005 E3m3 of natural gas consumed in 1990 at Suncor and Syncrude

[10] Based on the ERCB figure of 1,435,023 E3m3 of fuel gas consumed in 1990 at Suncor and Syncrude

[11] Total gas consumption according to utility billings - does not include any fuel gas

[12] Total number of gas plants taken from ERCB Oct/91 figures (includes straddle and fractionation plants)

[13] Figure based on 3% of total gas throughput for 1990 (i.e. 45% capacity factor of 662 Tcf)

[14] Total refineries: 6

[15] Total cement plants: 2

[16] Includes gas used for power generation

CONSUMER PROFILE - MARCH 16, 1992

OILSANDS INSITU PRODUCTION:

Project	Bitumen Production (bbls/day) [17]	Utility	Onsite Capacity (MW)	Onsite Generation (MWh)	Power Purchases (MWh)
Esso Cold Lake	69,129	APL			
Shell Peace River	10,926	APL			
Amoco Elk Point	8,969	APL			
BP/PC Wolf Lake	6,965	APL			
Amoco Lindbergh	5,085	APL			
Suncor Burnt Lake	516	APL			
Murphy Cold Lake	326	APL			
Amoco Primrose	150	APL			
Amoco Soars Lake	0	APL			
Total onsite capacity:			0		
Total onsite generation:				0	
Total power purchases (all customers):					671,755

OILSANDS MINING:

Project	Synthetic Crude Oil Production (bbls/day) [18]	Utility	Onsite Capacity (MW)	Onsite Generation (MWh)	Power Purchases (MWh)
Syncrude Fort McMurray	151,210	APL	269	1,226,900	
Suncor Fort McMurray	62,932	APL	64	358,800	
OSLO (proposed)	0	APL			
Total onsite capacity:			333		
Total onsite generation [19]:				1,585,700	
Total power purchases (all customers) [20]:					392,036

SOURCE: Energy Resources Conservation Board
Alberta electric utilities

[17] Production is in average barrels per day for the first half of 1991.

[18] Production is in average barrels per day for the first half of 1991.

[19] ERCB figure: 1601.3 GWh

[20] ERCB figure: 389.8 GWh

GAS PLANTS [21]

Gas Plants Raw Gas Capacity (1000 m3/d)	Type of Gas Plants [22]			Power Requirements		
	Sweet/no NGL processing (#, % capacity)	Sweet/NGL processing (#, % capacity)	Sour/NGL processing [23] (#, % capacity)	Onsite Capacity (MW)	Onsite Generation (MWh)	Power Purchases (MWh)
0-999	275 (68%)	230 (35%)	18 (7%)			
1000-1999	11 (16%)	12 (11%)	11 (9%)			
2000-2999	1 (2%)	5 (7%)	5 (7%)			
3000-3999	3 (10%)	1 (2%)	5 (8%)			
4000-4999	1 (4%)	3 (7%)	1 (3%)			
5000-5999			1 (3%)			
6000-6999		2 (7%)	2 (7%)			
7000-7999		2 (8%)	2 (9%)			
8000-8999			2 (10%)			
9000-9999			1 (6%)			
10000-10999		1 (6%)	1 (6%)			
11000-11999			1 (7%)			
12000-12999						
13000-13999		1 (8%)	1 (8%)			
14000-14999						
15000-15999						
16000-16999		1 (9%)				
17000-17999			1 (10%)			
Total #	291 (100%)	258 (100%)	52 (100%)			
Capacity (million m3/yr)	36,611	65,946	63,565			
Total number of gas plants: Total gas plant capacity: Total onsite capacity: Total onsite generation: Total power purchases (all plants):			601 166,122	34.3	26,300	4,813,300

SOURCE: Energy Resources Conservation Board, Alberta electrical utilities, industry data bases

[21] Excludes six straddle plants and seven NGL fractionation plants.

[22] ERCB figures (October 1991) - Number of approved facilities:

Sweet	384	
Sour (non recovery)	178	Includes chemical absorption, injection, acid gas flaring & other
Sulphur recovery	61	
TOTAL:	623	

[23] Plants defined as Sour/NGL processing are those that have sulphur recovery

OILFIELD - GAS FLARING [24]

FOR THE MONTH OF NOVEMBER, 1991 (ERCB DATA)	
PARTICULARS	Flared Gas (E3m3)
Total amount of gas flared at all battery sites	143,659
Total amount of gas flared at batteries with flare volumes equal or greater than 150,000 m3 - percent of total flared for the month: 45.1% - number of batteries with flare volumes equal or greater than 150,000 m3: 206	64,847
a) Total amount of sour gas flared (concentrations above 1 mole/kmole of H_2S): Total amount of sweet gas flared:	15,945 48,902
b) Flared sour gas - with high probability of continuous flaring (no gas is delivered into NOVA or used as fuel gas):	10,186
c) Flared sweet gas - with high probability of continuous flaring (i.e. no gas is delivered into NOVA or used as fuel gas):	37,719

SOURCE: Energy Resources Conservation Board

REFINERIES:

Refinery	Crude Oil Production (b/cd)	Production Capacity (M^3/cd)	Utility	Onsite Capacity (MW)	Onsite Generation (MWh)	Power Purchases (MWh)
Esso Petroleum Edmonton	164,875	26,200	TAU			
Petro Canada Edmonton	121,140	19,250	TAU			
Shell Canada Scotford	56,000	8,900	TAU			
Turbo Resources Calgary	27,625	4,390	TAU			
Husky Oil Lloydminster	23,315	3,705	APL			
Parkland Industries Bowden	6,700	1,064	TAU			
Total onsite capacity:				6.9		
Total onsite generation:					21,000	
Total power purchases (all customers):						1,023,792

SOURCE: Energy Resources Conservation Board, Economic Development and Trade, Alberta electric utilities

[24] Only flares at batteries included as flares at refineries and gas plants, for operation reasons, tend to be intermittent

CONSUMER PROFILE - MARCH 16, 1992

PETROCHEMICAL/CHEMICAL:

Company	Utility	Products	Annual Production (Kt)	Onsite Capacity (MW)	Onsite Generation (MWh)	Power Purchases (MWh)
Esso Chemical Redwater	TAU	Ammonia, Ammonium Nitrate, Sulphuric Acid, Phosphoric Acid, Phosphate, Nitric Acid, Urea	3290			
Dow Chemical Fort Saskatchewan	TAU	Chlor-Alkali, Glycols, Ethanolamines, HCl, Vinyl Chloride, Monomer, Ethylene Glycole, Chlor-Alkali, Caustic Soda, Styrofoam, LLOPE	2130	180	1,285,900 (25)	
Novacor Joffre	TAU	Ethylene, LLDPE	1970			
Sherritt Gordon Fort Saskatchewan	TAU	Ammonia, Sulphuric Acid, Phosphoric Acid, Urea, Ammonium Sulfate, Ammonium Phosphate	1820	7.8	16,500	
Canadian Fertilizers Medicine Hat	MH	Ammonia, Urea	1475			
Cominco Caresland	TAU	Ammonia, Urea	1050			
Celanese Canada Edmonton	EP	Formaldehyde, Pentaerythritol, Acetic Acid, Vinyl Acetate, Methanol	984	19.8	75,200	
Shell Canada Scotford	TAU	Benzene, Styrene	723			
Novacor Med. Hat	MH	Methanol	720			
Union Carbide Prentiss	TAU	Ethylene Glycol	366			
Cominco/Alta Energy Joffre	TAU	Ammonia	350			
I.C.I. Canada Caresland	TAU	Ammonium Nitrate	225			
B.F. Goodrich Fort Saskatchewan	TAU	Polyvinyl Chloride	110			
AT Plastics Edmn	EP	Phenolic & Formaldehyde Resins	75			
Albchem Industries Bruderheim	TAU	Sodium Chlorate	55			
Albright & Wilson Grande Prairie	APL	Sodium Chlorate	45			
Du Pont Gibbons	TAU	Hydrogen Peroxide	36			
Cancarb Med. Hat	MH	Carbon Black	20			
Cominco Calgary	Cal	Ammonium Nitrate	20			
Borden Ind. Edmn	EP	Phenolic & Formaldehyde Resins	10			
Thio-Pet Chemicals Fort Saskatchewan	TAU	Carbon Disulfide	5			
Total onsite capacity:				207.6		
Total onsite generation:					1,377,600	
Total power purchases (all customers):						2,727,883

SOURCE: Alberta electrical utilities, Alberta Economic Development & Trade, Energy Resources Conservation Board

25 Onsite generation estimated.

PULP MILLS (1990 data):

Type	Company	Production (a.d.t/yr)	Utility	Wood Residues (o.d.t/yr)	Onsite Capacity (MW)	Onsite Generation (MWh)
Kraft	Weldwood, Hinton	385,000	TAU		50	265,000
Kraft	Daishowa, Peace River	340,000	APL		40	102,000
Kraft	Procter Gamble, Grande Prairie	280,000	APL		32	262,000
CTMP	Alta Newsprint, Whitecourt	220,000	TAU			
CTMP	Millar Western, Whitecourt	210,000	TAU			
CTMP	Alberta Energy, Slave Lake	110,000	APL			
Kraft	ALPAC, Athabasca		TAU		95 (proposed)	
Total residues [26]:				473,054		
Total onsite capacity (current):					122	
Total onsite generation:						629,000

PANELBOARD MILLS (1990 data):

Type	Company	Utility	Residues (o.d.t/yr)	Onsite Capacity (MW)	Onsite Generation (MWh)
OSB	Weyerhaeuser, Drayton Valley	TAU			
OSB	Weyerhaeuser, Edson	TAU			
Veneer	Zeidler, Slave Lake/Edmonton [27]	APL/EP			
Fibre board	Alberta Energy, Blue Ridge/Whitecourt	TAU			
OSB	Weldwood, Slave Lake [28]	APL			
Plywood	CANFOR, Grande Prairie [29]	APL			
Plywood	Crestbrook, Ft. McLeod [30]	TAU			
Total residues:			127,859		
Total onsite capacity:				0	

SOURCE: Silvacom Waste Wood Inventory, 1991; Alberta electrical utilities, Energy Resources Conservation Board

[26] Residue volumes may be understated as some mills were not operating at full volume in 1991.

[27] Wet veneer produced in Slave Lake, dried in Edmonton.

[28] Shut down in 1991.

[29] Shut down in 1991.

[30] Shut down in 1991.

SAWMILLS (1990 data):

Name/Location	Onsite Capacity (MW)	Residue (o.d.t./yr)	Current Method of Disposal
Atlas Forest Products		26,760	
Bissell/Enilda		15,009	Beehive Burner
Blue Ridge		122,888	Beehive Burner
Boucher/Nampa		18,656	Beehive Burner
Brewster/Red Earth		37,993	Beehive Burner
Buchanan/High Prairie		36,394	Beehive Burner
Canfor/Grande Prairie		85,335	Silo Burner
Canfor/Hines Creek		53,051	Beehive Burner
Cowley Forest Products		20,180	
Grande Cache F.P.		66,543	Beehive Burner
High Level F.P.		170,242	Beehive Burner
La Crete		9,347	
Millar/Whitecourt		106,386	Beehive Burner
Mostowich/Fox Creek		15,919	Beehive Burner
Northland/Ft McMurray		45,753	Beehive Burner
P & G/Grande Prairie		85,568	Power Boiler
Rinke & Sons/Blairmore		1710	
Rocky Wood Preservers/Rocky Mt. House		13,580	
Spray Lakes Sawmills/Cochrane		61,535	
Sundance/Edson		52,361	Silo Burner
Sunpine Forest Products/Sundre		67,545	
Tall Pine Timber/Lodgepole		10,570	
Timeu/Ft Assiniboine		6,468	
Tomen/Ft Assiniboine		13,582	Beehive Burner
Vanderwell/Slave Lake		35,937	Beehive Burner
Weldwood/Hinton		55,886	Power Boiler
Weyerhaeuser/Drayton		79,860	Beehive Burner
Weyerhaeuser/Boyle		40,546	Beehive Burner
Zavisha/Hines Creek		7,102	Beehive Burner
Zeidler/Slave Lake		41,147	Beehive Burner
Total residues: [31] Total onsite capacity:	0	1,403,853	

31 Numbers are taken from the Silvacom Wood Residue Inventory which also quotes total residues from the 30 large sawmills (above 4 MMFBM/year) to be 1,300,826 odt.

SUMMARY TABLE - FOREST INDUSTRY:

Industry	Number of Mills	Residues (o.d.t./yr)	Onsite Capacity (MW)	Onsite Generation (MWh)	Power Purchases (MWh)
Pulp & Paper Mills	6	473,054	122	629,000	
Panelboard Mills	4	127,859	0		
Sawmills (Large & Small)	30 Large	1,328,876	0		
Total	40	1,929,789	122	629,000	1,035,343

SOURCE: Silvacom Waste Wood Inventory, 1991; Alberta electrical utilities; Energy Resources Conservation Board

MUNICIPAL SOLID WASTE:

Quantities of Wastes Landfilled In Alberta, 1987 (tonnes)		
Category	Canadian Average (1979)	Edmonton Survey (1987)
paper	666,400	413,000
organics (grass, wood, food)	693,900	780,000
metals	120,800	98,000
glass	120,800	24,000
plastics	84,200	153,000
textiles	78,780	20,000

Composition of Edmonton Regional Waste - Recorded Averages by Weight				
Category	Residential	Commercial/Industrial	Edmonton Average	Canadian Average
Paper/cardboard	35.4%	12.9%	22.6%	36%
Organics	46.7	39.5	42.6	38
Plastics	10.0	7.1	8.3	5
Metals	3.0	7.1	5.3	7
Minerals	0.8	33.0	19.2	4
Glass	1.5	included above	0.6	7
Textiles	2.6	0.4	1.4	4

Tonnes of Waste Generated		
Source	1987	1991
Edmonton & Calgary	1,073,400	1,245,985
Other Cities over 10,000	221,400	251,182
Rural areas & small communities	536,000	555,667
Total	1,830,800	2,052,834

SOURCE: Economic Development and Trade (An Economics study of the Recycling Industry In Alberta); Alberta Energy

FOOD PROCESSING/BREWERIES:

Type	Size of Facility (number of employees)			Onsite Capacity (MW)	Onsite Generation (MWh)	Power Purchases (MWh)
	1 - 25	26 - 100	100 plus			
Animal byproducts	2	5	0			
Bakeries	24	15	4			
Beverages (alcoholic)	6	2	4			
Beverages (nonalcoholic)	14	6	4			
Confections (chocolates, etc.)	9	0	0			
Dairies	24	14	5			
Eggs	9	1	2			
Fish	3	2	1			
Forage Seeds	15	1	0			
Fruits and vegetables	30	14	5			
Grains (processing)	4	3	3			
Honey	13	1	0			
Livestock genetics	11	2	0			
Meat (federal)	4	8	17			
Meat (provincial)	60	1	0			
Meat (other processing)	24	4	0			
Misc. (seasonings, sugar)	4	2	1			
Oats	3	1	0			
Oilseeds (refining/processing)	4	4	1			
Pasta	12	1	0			
Peat Moss	3	0	2			
Pet foods	3	2	1			
Poultry	8	2	4			
Primary feed mills	23	4	2			
Processed forage	14	7	1			
Snack Foods	6	2	1			
Specialty crops	9	2	0			
Specialty feeds	11	0	0			
Specialty foods	27	4	0			
Total number of facilities:	379	110	58			
Total onsite capacity:				6.3		
Total onsite generation:					11,500	
Total power purchases (all customers):						505,557

SOURCE: Alberta Agriculture, Energy Resources Conservation Board, Alberta electric utilities

Appendix B

Summary Tables of Results

Summary of Results - Oil Sands Mining

Operating Mode	Cogeneration Sizing Strategy	System Type	Capacity (MW)
Buy All/Sell All	**Thermal Peak**	**Gas Turbine w/ Heat Recovery**	**177.42**
Buy Def./Sell Excess	Electric Peak	Gas Turbine w/ Heat Recovery	65.00

System description - Oil Sands Mining

N. Gas ->	A:-$0.05/cu.m. ($1.32/GJ)				B:-$0.10/cu.m. ($2.64/GJ)				C:-$0.15/cu.m. ($3.96/GJ)			
Buyback ¢/kWh->	1.00	3.00	5.25	7.50	1.00	3.00	5.25	7.50	1.00	3.00	5.25	7.50
Electric Rate	Simple Payback (Years)											
R1: 3.0¢/kWh	7.0	**6.3**	**2.8**	**1.8**	18.4	**12.3**	**3.6**	**2.1**	20.0	**20.0**	**5.0**	**2.5**
R2: 5.25¢/kWh	2.9	2.9	**2.8**	**1.8**	4.0	4.0	**3.6**	**2.1**	6.2	6.2	**5.0**	**2.5**
R3: 7.5¢/kWh	1.9	1.9	1.9	**1.8**	2.2	2.2	2.2	**2.1**	2.8	2.8	2.8	**2.5**
	Internal Rate of Return											
R1: 3.0¢/kWh	0.10	**0.11**	**0.25**	**0.38**	0.00	**0.03**	**0.20**	**0.33**	0.00	**0.00**	**0.15**	**0.28**
R2: 5.25¢/kWh	0.24	0.24	**0.25**	**0.38**	0.18	0.18	**0.20**	**0.33**	0.11	0.11	**0.15**	**0.28**
R3: 7.5¢/kWh	0.37	0.37	0.37	**0.38**	0.31	0.31	0.31	**0.33**	0.26	0.26	0.26	**0.28**
	Rate of Return on Equity											
R1: 3.0¢/kWh	0.46	**0.53**	**1.17**	**1.71**	0.00	**0.01**	**0.94**	**1.50**	0.00	**0.00**	**0.69**	**1.29**
R2: 5.25¢/kWh	1.12	1.12	**1.17**	**1.71**	0.86	0.86	**0.94**	**1.50**	0.54	0.54	**0.69**	**1.29**
R3: 7.5¢/kWh	1.67	1.67	1.67	**1.71**	1.43	1.43	1.43	**1.50**	1.18	1.18	1.18	**1.29**

Economics of cogeneration - Oil Sands Mining

N. Gas ->	A:-$0.05/cu.m. ($1.32/GJ)		B:-$0.10/cu.m. ($2.64/GJ)		C:-$0.15/cu.m ($3.96/GJ)	
Discount Rate: 7%	Levelized Cost (¢/kWh)					
Term: 15 yrs	2.54	**2.36**	3.55	**3.24**	4.56	**4.12**
Term: 20 yrs	2.37	**2.20**	3.39	**3.08**	4.40	**3.96**

Levelized cost - Oil Sands Mining

	1992		2005	
	Electric Peak	Thermal Peak	Electric Peak	Thermal Peak
Number of Facilities	2.8		5.3	
Representative Capacity (MW)	65.00	**177.42**	65.00	**177.42**
Technical Potential (MW)	182.00	**496.78**	344.50	**940.33**
Percent Accepting	4.6%	**4.9%**	0.0%	**0.0%**
Economic Potential (MW)	8.37	**24.20**	0.00	**0.00**
1990 Implementation (MW)	333.00			

Base case summary - Oil Sands Mining

Summary of Results - Oil Sands In-Situ

Operating Mode	Cogeneration Sizing Strategy	System Type	Capacity (MW)
Buy All/Sell All	**Thermal Peak**	**Gas Turbine w/ Heat Recovery**	**39.69**
Buy Def./Sell Excess	Electric Peak	Gas Turbine w/ Heat Recovery	20.00

System description - Oil Sands In-Situ

N. Gas ->	**A:-$0.05/cu.m. ($1.32/GJ)**				**B:-$0.10/cu.m. ($2.64/GJ)**				**C:-$0.15/cu.m. ($3.96/GJ)**			
Buyback ¢/kWh->	1.00	3.00	5.25	7.50	1.00	3.00	5.25	7.50	1.00	3.00	5.25	7.50
Electric Rate	**Simple Payback (Years)**											
R1: 3.0¢/kWh	13.6	**12.1**	**4.7**	**2.9**	20.0	**20.0**	**6.7**	**3.6**	20.0	**20.0**	**12.0**	**4.7**
R2: 5.25¢/kWh	4.9	4.9	**4.7**	**2.9**	7.6	7.6	**6.7**	**3.6**	17.0	17.0	**12.0**	**4.7**
R3: 7.5¢/kWh	3.0	3.0	3.0	**2.9**	3.8	3.8	3.8	**3.6**	5.3	5.3	5.3	**4.7**
	Internal Rate of Return											
R1: 3.0¢/kWh	0.03	**0.04**	**0.16**	**0.25**	0.00	**0.00**	**0.10**	**0.20**	0.00	**0.00**	**0.04**	**0.16**
R2: 5.25¢/kWh	0.15	0.15	**0.16**	**0.25**	0.09	0.09	**0.10**	**0.20**	0.00	0.00	**0.04**	**0.16**
R3: 7.5¢/kWh	0.24	0.24	0.24	**0.25**	0.19	0.19	0.19	**0.20**	0.14	0.14	0.14	**0.16**
	Rate of Return on Equity											
R1: 3.0¢/kWh	0.00	**0.02**	**0.74**	**1.14**	0.00	**0.00**	**0.48**	**0.95**	0.00	**0.00**	**0.02**	**0.74**
R2: 5.25¢/kWh	0.70	0.70	**0.74**	**1.14**	0.40	0.40	**0.48**	**0.95**	0.00	0.00	**0.02**	**0.74**
R3: 7.5¢/kWh	1.11	1.11	1.11	**1.14**	0.89	0.89	0.89	**0.95**	0.65	0.65	0.65	**0.74**

Economics of cogeneration - Oil Sands In-Situ

N. Gas ->	**A:-$0.05/cu.m. ($1.32/GJ)**		**B:-$0.10/cu.m. ($2.64/GJ)**		**C:-$0.15/cu.m. ($3.96/GJ)**	
Discount Rate: 7%	Levelized Cost (¢/kWh)					
Term: 15 yrs	3.50	**3.34**	4.75	**4.46**	6.00	**5.58**
Term: 20 yrs	3.25	**3.09**	4.50	**4.21**	5.75	**5.33**

Levelized cost - Oil Sands In-Situ

	1992		2005	
	Electric Peak	Thermal Peak	Electric Peak	Thermal Peak
Number of Facilities	5.8		15.8	
Representative Capacity (MW)	20.00	**39.69**	20.00	**39.69**
Technical Potential (MW)	116.00	**230.20**	316.00	**627.10**
Percent Accepting	0.0%	**0.0%**	0.0%	**0.0%**
Economic Potential (MW)	0.00	**0.00**	0.00	**0.00**
1990 Implementation (MW)	0			

Base case summary - Oil Sands In-Situ

Summary of Results - Oil Refineries and Upgraders

Operating Mode	Cogeneration Sizing Strategy	System Type	Capacity (MW)
Buy All/Sell All	Thermal Peak	Gas Turbine w/ Heat Recovery	79.07
Buy Def./Sell Excess	Electric Peak	Gas Turbine w/ Heat Recovery	40.00

System description - Oil Refineries and Upgraders

N. Gas ->	A:-$0.05/cu.m. ($1.32/GJ)				B:-$0.10/cu.m. ($2.64/GJ)				C:-$0.15/cu.m. ($3.96/GJ)			
Buyback ¢/kWh->	1.00	3.00	5.25	7.50	1.00	3.00	5.25	7.50	1.00	3.00	5.25	7.50
Electric Rate	Simple Payback (Years)											
R1: 3.0¢/kWh	7.6	6.8	2.9	1.9	20.0	17.5	3.9	2.2	20.0	20.0	6.1	2.8
R2: 5.25¢/kWh	3.0	3.0	2.9	1.9	4.4	4.4	3.9	2.2	8.0	8.0	6.1	2.8
R3: 7.5¢/kWh	1.9	1.9	1.9	1.9	2.4	2.4	2.4	2.2	3.1	3.1	3.1	2.8
	Internal Rate of Return											
R1: 3.0¢/kWh	0.09	0.10	0.25	0.37	0.00	0.00	0.19	0.31	0.00	0.00	0.12	0.26
R2: 5.25¢/kWh	0.24	0.24	0.25	0.37	0.16	0.16	0.19	0.31	0.08	0.08	0.12	0.26
R3: 7.5¢/kWh	0.36	0.36	0.36	0.37	0.30	0.30	0.30	0.31	0.23	0.23	0.23	0.26
	Rate of Return on Equity											
R1: 3.0¢/kWh	0.40	0.47	1.13	1.68	0.00	0.00	0.87	1.43	0.00	0.00	0.56	1.19
R2: 5.25¢/kWh	1.09	1.09	1.13	1.68	0.78	0.78	0.87	1.43	0.36	0.36	0.56	1.19
R3: 7.5¢/kWh	1.64	1.64	1.64	1.68	1.36	1.36	1.36	1.43	1.07	1.07	1.07	1.19

Economics of cogeneration - Oil Refineries and Upgraders

N. Gas ->	A:-$0.05/cu.m. ($1.32/GJ)		B:-$0.10/cu.m. ($2.64/GJ)		C:-$0.15/cu.m. ($3.96/GJ)	
Discount Rate: 7%	Levelized Cost (¢/kWh)					
Term: 15 yrs	2.67	2.50	3.83	3.52	5.00	4.54
Term: 20 yrs	2.51	2.34	3.67	3.35	4.83	4.37

Levelized cost - Oil Refineries and Upgraders

	1992		2005	
	Electric Peak	Thermal Peak	Electric Peak	Thermal Peak
Number of Facilities	2.6		3.4	
Representative Capacity (MW)	40.00	79.07	40.00	79.07
Technical Potential (MW)	104.00	205.58	136.00	268.84
Percent Accepting	3.8%	4.7%	0.0%	0.0%
Economic Potential (MW)	3.97	9.62	0.00	0.00
1990 Implementation (MW)	6.9			

Base case summary - Oil Refineries and Upgraders

Summary of Results - Kraft Pulp Mills

Operating Mode	Cogeneration Sizing Strategy	System Type	Capacity (MW)
Buy All/Sell All	**Thermal Peak**	**Gas Turbine w/ Heat Recovery**	**149.72**
Buy Def./Sell Excess	Electric Peak	Gas Turbine w/ Heat Recovery	42.00

System description - Kraft Pulp Mills

Wood Cost->	A:$-10/ODtonne				B:$0/ODtonne				C:$10/ODtonne			
Buyback ¢/kWh->	1.00	3.00	5.25	7.50	1.00	3.00	5.25	7.50	1.00	3.00	5.25	7.50
Electric Rate	Simple Payback (Years)											
R1: 3.0¢/kWh	9.4	8.9	4.1	2.7	11.7	10.8	4.5	2.8	15.5	13.6	4.9	3.0
R2: 5.25¢/kWh	4.2	4.2	4.1	2.7	4.6	4.6	4.5	2.8	5.1	5.1	4.9	3.0
R3: 7.5¢/kWh	2.7	2.7	2.7	2.7	2.9	2.9	2.9	2.8	3.0	3.0	3.0	3.0
	Internal Rate of Return											
R1: 3.0¢/kWh	0.06	0.07	0.18	0.27	0.04	0.05	0.16	0.25	0.01	0.02	0.15	0.24
R2: 5.25¢/kWh	0.17	0.17	0.18	0.27	0.16	0.16	0.16	0.25	0.14	0.14	0.15	0.24
R3: 7.5¢/kWh	0.26	0.26	0.26	0.27	0.25	0.25	0.25	0.25	0.23	0.23	0.23	0.24
	Rate of Return on Equity											
R1: 3.0¢/kWh	0.20	0.25	0.83	1.22	0.02	0.07	0.77	1.16	0.00	0.00	0.70	1.11
R2: 5.25¢/kWh	0.81	0.81	0.83	1.22	0.74	0.4	0.77	1.16	0.67	0.67	0.70	1.11
R3: 7.5¢/kWh	1.20	1.20	1.20	1.22	1.14	1.14	1.14	1.16	1.08	1.08	1.08	1.11

Economics of cogeneration - Kraft pulp mills

Wood ->	A:$-10/ODtonne		B:$0/ODtonne		C:$10/ODtonne	
Discount Rate: 7%	Levelized Cost (¢/kWh)					
Term: 15 yrs	2.93	2.84	3.29	3.17	3.65	3.50
Term: 20 yrs	2.68	2.60	3.04	2.93	3.41	3.25

Levelized cost - Kraft pulp mills

	1992		2005	
	Electric Peak	Thermal Peak	Electric Peak	Thermal Peak
Number of Facilities	5.0		7.0	
Representative Capacity (MW)	42.00	149.72	42.00	149.72
Technical Potential (MW)	210.00	748.60	294.00	1048.04
Percent Accepting	0.0%	0.2%	0.0%	0.2%
Economic Potential (MW)	0.00	1.50	0.00	1.50
Implementation (MW)	217*			

*Based on 1990 implementation of 122 MW plus 95 MW at ALPAC facility.

Base case summary - Kraft pulp mills

Summary of Results - Petrochemical and Chemical Plants

Operating Mode	Cogeneration Sizing Strategy	System Type	Capacity (MW)
Buy All/Sell All	**Thermal Peak**	**Gas Turbine w/ Heat Recovery**	**73.33**
Buy Def./Sell Excess	Electric Peak	Gas Turbine w/ Heat Recovery	27.88

System description - Petrochemical and chemical plants

N. Gas ->	**A:-$0.05/cu.m. ($1.32/GJ)**				**B:-$0.10/cu.m. ($2.64/GJ)**				**C:-$0.15/cu.m. ($3.96/GJ)**			
Buyback ¢/kWh->	1.00	3.00	5.25	7.50	1.00	3.00	5.25	7.50	1.00	3.00	5.25	7.50
Electric Rate	**Simple Payback (Years)**											
R1: 3.0¢/kWh	9.2	7.5	3.0	1.9	20.0	20.0	4.4	2.3	20.0	20.0	7.8	3.1
R2: 5.25¢/kWh	3.5	3.3	3.0	1.9	5.6	5.0	4.4	2.3	12.9	10.1	7.8	3.1
R3: 7.5¢/kWh	2.2	2.1	2.0	1.9	2.8	2.7	2.5	2.3	4.0	3.7	3.4	3.1
	Internal Rate of Return											
R1: 3.0¢/kWh	0.06	0.09	0.24	0.36	0.00	0.00	0.17	0.30	0.00	0.00	0.08	0.23
R2: 5.25¢/kWh	0.20	0.22	0.24	0.36	0.13	0.15	0.17	0.30	0.03	0.05	0.08	0.23
R3: 7.5¢/kWh	0.32	0.33	0.34	0.36	0.25	0.27	0.28	0.30	0.18	0.20	0.21	0.23
	Rate of Return on Equity											
R1: 3.0¢/kWh	0.23	0.41	1.10	1.64	0.00	0.00	0.79	1.37	0.00	0.00	0.37	1.08
R2: 5.25¢/kWh	0.95	1.01	1.10	1.64	0.61	0.69	0.79	1.37	0.00	0.12	0.37	1.08
R3: 7.5¢/kWh	1.44	1.50	1.57	1.64	1.16	1.22	1.29	1.37	0.86	0.92	0.99	1.08

Economics of cogeneration - Petrochemical and chemical plants

N. Gas ->	**A:-$0.05/cu.m. ($1.32/GJ)**		**B:-$0.10/cu.m. ($2.64/GJ)**		**C:-$0.15/cu.m. ($3.96/GJ)**	
Discount Rate: 7%	Levelized Cost (¢/kWh)					
Term: 15 yrs	2.69	2.64	3.86	3.81	5.02	4.97
Term: 20 yrs	2.53	2.48	3.69	3.64	4.86	4.80

Levelized cost - Petrochemical and chemical plants

	1992		2005	
	Electric Peak	Thermal Peak	Electric Peak	Thermal Peak
Number of Facilities	19		49	
Representative Capacity (MW)	27.88	73.33	27.88	73.33
Technical Potential (MW)	529.72	1393.27	1366.12	3593.17
Percent Accepting	1.2%	4.0%	0.0%	0.0%
Economic Potential (MW)	6.36	55.00	0.00	0.00
1990 Implementation (MW)	208			

Base case summary - Petrochemical and chemical plants

Summary of Results - Large Educational

Operating Mode	Cogeneration Sizing Strategy	System Type	Capacity (MW)
Buy All/Sell All	Thermal Peak	Gas Engine w/ Heat Recovery	5.70
Buy Def./Sell Excess	Electric Peak	Gas Engine w/ Heat Recovery	2.86

System description - Large educational

N. Gas ->	A:-$0.05/cu.m. ($1.32/GJ)				B:-$0.10/cu.m. ($2.64/GJ)				C:-$0.15/cu.m. ($3.96/GJ)			
Buyback ¢/kWh->	1.00	3.00	5.25	7.50	1.00	3.00	5.25	7.50	1.00	3.00	5.25	7.50
Electric Rate	Simple Payback (Years)											
R1: 3.0¢/kWh	20.0	20.0	10.2	5.1	20.0	20.0	18.8	6.6	20.0	20.0	20.0	9.3
R2: 5.25¢/kWh	9.6	9.6	9.6	5.1	15.2	15.2	15.2	6.6	20.0	20.0	20.0	9.3
R3: 7.5¢/kWh	4.9	4.9	4.9	4.9	6.1	6.1	6.1	6.1	7.9	7.9	7.9	7.9
	Internal Rate of Return											
R1: 3.0¢/kWh	0.00	0.00	0.05	0.14	0.00	0.00	0.00	0.10	0.00	0.00	0.00	0.06
R2: 5.25¢/kWh	0.06	0.06	0.06	0.14	0.01	0.01	0.01	0.10	0.00	0.00	0.00	0.06
R3: 7.5¢/kWh	0.15	0.15	0.15	0.15	0.12	0.12	0.12	0.12	0.08	0.08	0.08	0.08
	Rate of Return on Equity											
R1: 3.0¢/kWh	0.00	0.00	0.06	0.25	0.00	0.00	0.00	0.16	0.00	0.00	0.00	0.08
R2: 5.25¢/kWh	0.07	0.07	0.07	0.25	0.00	0.00	0.00	0.16	0.00	0.00	0.00	0.08
R3: 7.5¢/kWh	0.26	0.26	0.26	0.26	0.18	0.18	0.18	0.18	0.11	0.11	0.11	0.11

Economics of cogeneration - Large educational

N. Gas ->	A:-$0.05/cu.m. ($1.32/GJ)		B:-$0.10/cu.m. ($2.64/GJ)		C:-$0.15/cu.m ($3.96/GJ)	
Discount Rate: 7%	Levelized Cost (¢/kWh)					
Term: 15 yrs	5.22	5.36	6.09	6.38	6.99	7.39
Term: 20 yrs	4.89	5.03	5.76	6.05	6.48	7.07

Levelized cost - Large educational

	1992		2005	
	Electric Peak	Thermal Peak	Electric Peak	Thermal Peak
Number of Facilities	10		11	
Representative Capacity (MW)	2.86	5.70	2.86	5.70
Technical Potential (MW)	28.60	57.00	31.46	62.70
Percent Accepting	1.2%	1.0%	0.0%	0.0%
Economic Potential (MW)	0.34	0.55	0.00	0.00
1990 Implementation (MW)	4.8			

Base case summary - Large educational

Summary of Results - Hospitals

Operating Mode	Cogeneration Sizing Strategy	System Type	Capacity (MW)
Buy All/Sell All	**Thermal Peak**	**Gas Engine w/ Heat Recovery**	6.59
Buy Def./Sell Excess	Electric Peak	Gas Engine w/ Heat Recovery	1.33

System description - Hospitals

N. Gas ->	**A:-$0.05/cu.m. ($1.32/GJ)**				**B:-$0.10/cu.m. ($2.64/GJ)**				**C:-$0.15/cu.m. ($3.96/GJ)**			
Buyback ¢/kWh->	1.00	3.00	5.25	7.50	1.00	3.00	5.25	7.50	1.00	3.00	5.25	7.50
Electric Rate	**Simple Payback (Years)**											
R1: 3.0¢/kWh	20.0	20.0	10.7	5.2	20.0	20.0	20.0	7.0	20.0	20.0	20.0	10.6
R2: 5.25¢/kWh	9.3	9.3	9.3	5.2	13.6	13.6	13.6	7.0	20.0	20.0	20.0	10.6
R3: 7.5¢/kWh	4.8	4.8	4.8	4.8	5.8	5.8	5.8	5.8	7.3	7.3	7.3	7.3
	Internal Rate of Return											
R1: 3.0¢/kWh	0.00	0.00	0.05	0.14	0.00	0.00	0.00	0.10	0.00	0.00	0.00	0.05
R2: 5.25¢/kWh	0.06	0.06	0.06	0.14	0.02	0.02	0.02	0.10	0.00	0.00	0.00	0.05
R3: 7.5¢/kWh	0.15	0.15	0.15	0.15	0.12	0.12	0.12	0.12	0.09	0.09	0.09	0.09
	Rate of Return on Equity											
R1: 3.0¢/kWh	0.00	0.00	0.05	0.24	0.00	0.00	0.00	0.14	0.00	0.00	0.00	0.05
R2: 5.25¢/kWh	0.08	0.08	0.08	0.24	0.01	0.01	0.01	0.14	0.00	0.00	0.00	0.05
R3: 7.5¢/kWh	0.27	0.27	0.27	0.27	0.20	0.20	0.20	0.20	0.13	0.13	0.13	0.13

Economics of cogeneration - Hospitals

N. Gas ->	**A:-$0.05/cu.m. ($1.32/GJ)**		**B:-$0.10/cu.m. ($2.64/GJ)**		**C:-$0.15/cu.m. ($3.96/GJ)**	
Discount Rate: 7%	Levelized Cost (¢/kWh)					
Term: 15 yrs	5.13	5.46	5.91	6.58	6.79	7.70
Term: 20 yrs	4.80	5.13	5.58	6.25	6.33	7.37

Levelized cost - Hospitals

	1992		2005	
	Electric Peak	Thermal Peak	Electric Peak	Thermal Peak
Number of Facilities	13		18	
Representative Capacity (MW)	1.33	6.59	1.33	6.59
Technical Potential (MW)	17.29	85.67	23.94	118.62
Percent Accepting	1.2%	0.4%	0.0%	0.0%
Economic Potential (MW)	0.21	0.31	0.00	0.00
1990 Implementation (MW)	22.9			

Base case summary - Hospitals

Summary of Results - Sweet Gas Plants

Dispatch Mode	Cogeneration Sizing Strategy	System Type	Capacity (MW)
Buy All/Sell All	**Thermal Peak**	**Gas Turbine w/ Heat Recovery**	**7.78**
Buy Def./Sell Excess	Electric Peak	Gas Turbine w/ Heat Recovery	2.70

System description - Sweet Gas Plants

N. Gas -> Buyback ¢/kWh->	**A:-$0.05/cu.m. ($1.32/GJ)** 1.00	3.00	5.25	7.50	**B:-$0.10/cu.m. ($2.64/GJ)** 1.00	3.00	5.25	7.50	**C:-$0.15/cu.m. ($3.96/GJ)** 1.00	3.00	5.25	7.50
Electric Rate	**Simple Payback (Years)**											
R1: 3.0¢/kWh	7.8	6.5	2.8	1.8	20.0	13.0	3.7	2.1	20.0	20.0	5.1	2.5
R2: 5.25¢/kWh	3.1	3.1	2.8	1.8	4.3	4.3	3.7	2.1	7.1	7.1	5.1	2.5
R3: 7.5¢/kWh	1.9	1.9	1.9	1.8	2.3	2.3	2.3	2.1	3.0	3.0	3.0	2.5
	Internal Rate of Return											
R1: 3.0¢/kWh	0.08	0.11	0.25	0.37	0.00	0.03	0.20	0.33	0.00	0.00	0.14	0.28
R2: 5.25¢/kWh	0.23	0.23	0.25	0.37	0.17	0.17	0.20	0.33	0.10	0.10	0.14	0.28
R3: 7.5¢/kWh	0.36	0.36	0.36	0.37	0.30	0.30	0.30	0.33	0.24	0.24	0.24	0.28
	Rate of Return on Equity											
R1: 3.0¢/kWh	0.37	0.51	1.16	1.70	0.00	0.00	0.93	1.49	0.00	0.00	0.68	1.28
R2: 5.25¢/kWh	1.08	1.08	1.16	1.70	0.80	0.80	0.93	1.49	0.44	0.44	0.68	1.28
R3: 7.5¢/kWh	1.62	1.62	1.62	1.70	1.37	1.37	1.37	1.49	1.11	1.11	1.11	1.28

Economics of cogeneration - Sweet Gas Plants

N. Gas ->	**A:-$0.05/cu.m. ($1.32/GJ)**		**B:-$0.10/cu.m. ($2.64/GJ)**		**C:-$0.15/cu.m ($3.96/GJ)**	
Discount Rate: 7%	Levelized Cost (¢/kWh)					
Term: 15 yrs	2.72	2.41	3.77	3.29	4.82	4.17
Term: 20 yrs	2.55	2.25	3.60	3.13	4.65	4.01

Levelized cost - Sweet Gas Plants

	1992		2005	
	Electric Peak	Thermal Peak	Electric Peak	Thermal Peak
Number of Facilities	12		18	
Representative Capacity (MW)	2.70	7.80	2.70	7.80
Technical Potential (MW)	32.40	93.60	48.60	140.40
Percent Accepting	3.6%	4.8%	0.0%	0.0%
Economic Potential (MW)	1.15	4.49	0.00	0.00
1990 Implementation (MW)	34*			

*including both sweet and sour plants, data was not available separately

Base case summary - Sweet Gas Plants

Summary of Results - Sour Gas Plants

Dispatch Mode	Cogeneration Sizing Strategy	System Type	Capacity (MW)
Buy All/Sell All	**Thermal Peak**	**Gas Turbine w/ Heat Recovery**	**12.63**
Buy Def./Sell Excess	Electric Peak	Gas Turbine w/ Heat Recovery	6.68

System description - Sour Gas Plants

N. Gas ->	A:-$0.05/cu.m. ($1.32/GJ)				B:-$0.10/cu.m. ($2.64/GJ)				C:-$0.15/cu.m. ($3.96/GJ)			
Buyback ¢/kWh->	1.00	3.00	5.25	7.50	1.00	3.00	5.25	7.50	1.00	3.00	5.25	7.50
Electric Rate	Simple Payback (Years)											
R1: 3.0¢/kWh	7.3	6.4	2.8	1.8	20.0	12.8	3.6	2.1	20.0	20.0	5.0	2.5
R2: 5.25¢/kWh	3.0	3.0	2.8	1.8	4.1	4.1	3.6	2.1	6.7	6.7	5.0	2.5
R3: 7.5¢/kWh	1.9	1.9	1.9	1.8	2.3	2.3	2.3	2.1	2.9	2.9	2.9	2.5
	Internal Rate of Return											
R1: 3.0¢/kWh	0.09	0.11	0.25	0.37	0.00	0.03	0.20	0.33	0.00	0.00	0.14	0.28
R2: 5.25¢/kWh	0.24	0.24	0.25	0.37	0.18	0.18	0.20	0.33	0.10	0.10	0.14	0.28
R3: 7.5¢/kWh	0.36	0.36	0.36	0.37	0.31	0.31	0.31	0.33	0.25	0.25	0.25	0.28
	Rate of Return on Equity											
R1: 3.0¢/kWh	0.42	0.51	1.16	1.70	0.00	0.00	0.93	1.49	0.00	0.00	0.68	1.28
R2: 5.25¢/kWh	1.10	1.10	1.16	1.70	0.83	0.83	0.93	1.49	0.49	0.49	0.68	1.28
R3: 7.5¢/kWh	1.65	1.65	1.65	1.70	1.40	1.40	1.40	1.49	1.14	1.14	1.14	1.28

Economics of cogeneration - Sour Gas Plants

N. Gas ->	A:-$0.05/cu.m. ($1.32/GJ)		B:-$0.10/cu.m. ($2.64/GJ)		C:-$0.15/cu.m ($3.96/GJ)	
Discount Rate: 7%	Levelized Cost (¢/kWh)					
Term: 15 yrs	2.62	2.40	3.66	3.28	4.71	4.16
Term: 20 yrs	2.45	2.23	3.50	3.11	4.55	3.99

Levelized cost - Sour Gas Plants

	1992		2005	
	Electric Peak	Thermal Peak	Electric Peak	Thermal Peak
Number of Facilities	16		23	
Representative Capacity (MW)	6.70	12.60	6.70	12.60
Technical Potential (MW)	107.2	201.60	154.10	289.80
Percent Accepting	4.2%	4.8%	0.0%	0.0%
Economic Potential (MW)	4.51	9.76	0.00	0.00
1990 Implementation (MW)	34*			

*including both sweet and sour gas plants - data was not available separately

Base case summary - Sour Gas Plants

Summary of Results - Food Processing/Breweries

Operating Mode	Cogeneration Sizing Strategy	System Type	Capacity (MW)
Buy All/Sell All	**Thermal Peak**	**Gas Engine w/ Heat Recovery**	**5.06**
Buy Def./Sell Excess	Electric Peak	Gas Engine w/ Heat Recovery	2.20

System description - Food industry

N. Gas ->	A:-$0.05/cu.m. ($1.32/GJ)				B:-$0.10/cu.m. ($2.64/GJ)				C:-$0.15/cu.m. ($3.96/GJ)			
Buyback ¢/kWh->	1.00	3.00	5.25	7.50	1.00	3.00	5.25	7.50	1.00	3.00	5.25	7.50
Electric Rate	Simple Payback (Years)											
R1: 3.0¢/kWh	20.0	20.0	8.6	4.7	20.0	20.0	11.2	5.3	20.0	20.0	15.9	6.2
R2: 5.25¢/kWh	9.1	9.1	8.6	4.7	12.8	12.8	11.2	5.3	20.0	20.0	15.9	6.2
R3: 7.5¢/kWh	4.8	4.8	4.8	4.7	5.7	5.7	5.7	5.3	6.9	6.9	6.9	6.2
	Internal Rate of Return											
R1: 3.0¢/kWh	0.00	0.00	0.07	0.16	0.00	0.00	0.04	0.13	0.00	0.00	0.01	0.11
R2: 5.25¢/kWh	0.07	0.07	0.07	0.16	0.03	0.03	0.04	0.13	0.00	0.00	0.01	0.11
R3: 7.5¢/kWh	0.15	0.15	0.15	0.16	0.13	0.13	0.13	0.13	0.10	0.10	0.10	0.11
	Rate of Return on Equity											
R1: 3.0¢/kWh	0.00	0.00	0.09	0.29	0.00	0.00	0.04	0.23	0.00	0.00	0.00	0.18
R2: 5.25¢/kWh	0.08	0.08	0.09	0.29	0.02	0.02	0.04	0.23	0.00	0.00	0.00	0.18
R3: 7.5¢/kWh	0.28	0.28	0.28	0.29	0.21	0.21	0.21	0.23	0.14	0.14	0.14	0.18

Economics of cogeneration - Food industry

N. Gas ->	A:-$0.05/cu.m. ($1.32/GJ)		B:-$0.10/cu.m. ($2.64/GJ)		C:-$0.15/cu.m ($3.96/GJ)	
Discount Rate: 7%	Levelized Cost (¢/kWh)					
Term: 15 yrs	5.08	4.95	5.81	5.55	6.54	6.16
Term: 20 yrs	4.75	4.62	5.48	5.22	6.21	5.83

Levelized cost - Food industry

	1992		2005	
	Electric Peak	Thermal Peak	Electric Peak	Thermal Peak
Number of Facilities	14		19	
Representative Capacity (MW)	2.20	5.06	2.20	5.06
Technical Potential (MW)	30.80	70.84	41.80	96.14
Percent Accepting	0.0%	0.0%	0.0%	0.0%
Economic Potential (MW)	0.00	0.00	0.00	0.00
1990 Implementation (MW)	6.3			

Base case summary - Food industry

Summary of Results - Turboexpanders

Electric Capacity Range (kW)	Average Capacity Assumed (kW)	Number of Sites	Technical Potential (MW)
< 100	50	22	1.10
100 - 200	150	12	1.80
200 - 500	350	16	5.60
500 - 1,000	750	3	2.25
> 1,000	1,200	5	6.00
TOTAL	288.79	58	16.75

Size distribution of potential turboexpander sites

	Simple Payback (Years) Buyback Rate			
Gas Price	1¢/kWh	3¢/kWh	5.25¢/kWh	7.5¢/kWh
$0.05/GJ	20.0	5.4	2.6	1.7
$0.10/GJ	20.0	6.7	2.9	1.8
$0.15/GJ	20.0	8.8	3.2	2.0

Table 3-52. Economics of turboexpanders - base case

	Simple Payback (Years) Buyback Rate			
Gas Price	1¢/kWh	3¢/kWh	5.25¢/kWh	7.5¢/kWh
$0.05/GJ	20.0	8.2	3.9	2.6
$0.10/GJ	20.0	10.1	4.3	2.8
$0.15/GJ	20.0	13.2	4.8	3.0

Economics of turboexpanders - high capital cost case

N. Gas -> Discount Rate: 7%		A: -$0.05/cu.m. ($1.32/GJ)	B: -$0.10/cu.m. ($2.64/GJ)	C: -$0.15/cu.m. ($3.96/GJ)
Capital Cost	Term	Levelized Cost (¢/kWh)		
$1000/kW	15 yrs	2.07	2.47	2.87
	20 yrs	1.91	2.31	2.71
$1500/kW	15 yrs	2.66	3.06	3.46
	20 yrs	2.41	2.81	3.21

Levelized cost - Turboexpanders

	1992	2005
Number of Facilities	58	90
Representative Capacity (MW)	0.29	0.29
Technical Potential (MW)	16.82	26.10
Percent Accepting	16.2%	4.7%
Economic Potential (MW)	2.72	1.23
1990 Implementation (MW)	0	

Base case summary - Turboexpanders

Summary of Results - Saw, Panelboard, and CTMP Mills

Wood ->	A: -$10/tonne				B: $0/tonne				C:$10/tonne			
Buyback ¢/kWh->	1.00	3.00	5.25	7.50	1.00	3.00	5.25	7.50	1.00	3.00	5.25	7.50
Simple Payback (Years)	20.0	20.0	9.2	5.5	20.0	20.0	11.3	6.2	20.0	20.0	14.6	7.1
Internal Rate of Return	0.00	0.00	0.06	0.13	0.00	0.00	0.04	0.11	0.00	0.00	0.02	0.09
Rate of Return on Equity	0.00	0.00	0.22	0.61	0.00	0.00	0.04	0.53	0.00	0.00	0.00	0.44

Economics of Saw, Panelboard, and CTMP Mills

Wood ->	A:-$10/tonne	B:$0/tonne	C:$10/tonne
Discount Rate: 7%	Levelized Cost (¢/kWh)		
Term: 15 yrs	4.64	5.27	5.89
Term: 20 yrs	4.20	4.83	5.45

Levelized cost - Saw, Panelboard, and CTMP Mills

	1992	2005
Number of Facilities	14	16
Representative Capacity (MW)	20.00	20.00
Technical Potential (MW)	280.00	320.00
Percent Accepting	0.0%	0.0%
Economic Potential (MW)	0.00	0.00
1990 Implementation (MW)	0	

Base case summary - Saw, Panelboard, and CTMP Mills

Summary of Results - Gas Flares

Buyback Price	3 ¢/kWh	5.25 ¢/kWh	7.5 ¢/kWh
Electric Revenue	222,749	389,810	556,872
Gas Royalty Charge (@ $0.02053 per m^3)	73,169	73,169	73,169
Equipment Maintenance Cost (@ 2.0¢/kWh)	148,499	148,499	148,499
Gross Revenues with Gas Royalty Charge	1,081	168,143	335,204
LOW COST SCENARIO - BASE CASE			
Capital Cost: $750 per kW	794,623	794,623	794,623
Simple Payback	735.0	4.7	2.4
Percent Accepting	0.0%	24.8%	65.0%
HIGH COST SCENARIO			
Capital Cost: $1,125 per kW	1,191,935	1,191,935	1,191,935
Simple Payback	1102.5	7.1	3.6
Percent Accepting	0.0%	4.5%	38.0%

Economics and market acceptance - Gas flares

Capital Cost ->	$750/kW	$1,125/kW
Discount Rate: 7%	Levelized Cost (¢/kWh)	
Term: 15 yrs	4.08	4.63
Term: 20 yrs	3.93	4.40

Levelized cost - gas flares

	1992	2005
Number of Facilities	127	127
Representative Capacity (MW)	1.06	1.06
Technical Potential (MW)	134.62	134.62
Percent Accepting	0.0%	0.0%
Economic Potential (MW)	0.00	0.00
1990 Implementation (MW)	0	

Base case summary - Gas flares

Summary of Results - MSW Plants

Annual Revenues (million $)				
Buyback Price (¢/kWh)	Tipping Fee ($/tonne)	$20	$35	$50
	Revenue (million $)	12.0	21.1	30.1
1.0	3.0	7.5	16.6	25.6
3.0	9.0	13.5	22.6	31.6
5.25	15.8	20.3	29.3	38.4
7.5	22.5	27.0	36.1	45.1

Note: Revenues have been adjusted for $7.5 million annual O&M cost

Revenue breakdown for MSW plants

Simple Payback (years)			
Buyback Price (¢/kWh)	Tipping Fee ($/tonne)		
	20	35	50
1.0	31.8	14.5	9.4
3.0	17.7	10.6	7.6
5.25	11.8	8.2	6.3
7.5	8.9	6.7	5.3

Based on capital cost of $240 million ($6,000/kW)

Economics of MSW plants

Discount Rate: 7%	Levelized Cost (¢/kWh)	
Tipping Fee	$20/OD tonne	$35/OD tonne
Term: 15 yrs	6.69	3.68
Term: 20 yrs	5.53	2.53

Levelized cost - MSW plants

	1992	2005
Number of Facilities	2.6	3
Representative Capacity (MW)	40.00	40.00
Technical Potential (MW)	104.00	120.00
Percent Accepting	0.4%	0.4%
Economic Potential (MW)	0.46	0.53
1990 Implementation (MW)	0	

Base case summary - MSW plants

Appendix C

Detailed Results from Sensitivity Analyses

Economic Potential (MW)	Size to Peak electric								
Electric Rate	3¢/kWh			5.25¢/kWh			7.5¢/kWh		
Segment	$1.32	$2.64	$3.96	$1.32	$2.64	$3.96	$1.32	$2.64	$3.96
Petrochemicals	6	0	0	208	66	0	365	292	149
Saw, panel board, CTMP	0	0	0	0	0	0	14	14	14
Kraft pulp mills	0	0	0	53	53	53	111	111	111
Oil sands mining	8	0	0	96	51	9	135	125	100
Gas flares	0	0	0	33	33	33	87	87	87
Oil sands in-situ	0	0	0	28	4	0	59	38	21
Sour gas plants	5	0	0	54	30	5	80	71	57
MSW	0	0	0	3	3	3	5	5	5
Refineries	4	0	0	53	27	3	77	67	50
Sweet gas plants	1	0	0	16	9	1	24	22	16
Education	0	0	0	7	1	1	28	29	29
Hospitals	0	0	0	4	2	1	16	17	17
Turboexpanders	3	1	0	10	9	8	13	13	12
Food industry	0	0	0	0	0	0	8	3	1
TOTALS:	28	1	1	566	289	118	1021	894	670

All numbers are rounded to the nearest MW. The rounded total may differ slightly from the sum of rounded segment contributions.

Table C-1. 1992 economic potential and gas price - electric peak sizing

Economic Potential (MW)	Size to Peak thermal								
Buyback Rate	3¢/kWh			5.25¢/kWh			7.5¢/kWh		
Segment	$1.32	$2.64	$3.96	$1.32	$2.64	$3.96	$1.32	$2.64	$3.96
Petrochemicals	55	0	0	704	366	50	1036	928	672
Saw, panel board, CTMP	0	0	0	0	0	0	14	14	14
Kraft pulp mills	2	2	2	194	194	194	412	412	412
Oil sands mining	24	0	0	274	184	117	374	354	308
Gas flares	0	0	0	33	33	33	87	87	87
Oil sands in-situ	0	0	0	57	11	0	122	85	57
Sour gas plants	10	0	0	111	75	48	152	144	125
MSW	0	0	0	3	3	3	5	5	5
Refineries	10	0	0	109	62	10	153	142	113
Sweet gas plants	4	0	0	52	33	20	70	67	58
Education	1	0	0	12	3	1	57	57	57
Hospitals	0	0	0	17	4	0	86	86	86
Turboexpanders	3	1	0	10	9	8	13	13	12
Food industry	0	0	0	1	0	0	18	13	3
TOTALS:	109	3	3	1577	977	484	2598	2406	2011

All numbers are rounded to the nearest MW. The rounded total may differ slightly from the sum of rounded segment contributions.

Table C-2. 1992 economic potential and gas price - thermal peak sizing

Economic Potential (MW)	Size to Peak electric					
Electric Rate	3¢/kWh		5.25¢/kWh		7.5¢/kWh	
Segment	1992	2005	1992	2005	1992	2005
Petrochemicals	25	0	313	372	405	973
Saw, panel board, CTMP	0	0	6	7	70	81
Kraft pulp mills	4	5	85	119	146	204
Oil sands mining	34	0	126	174	143	263
Gas flares	0	0	52	52	101	101
Oil sands in-situ	1	0	41	33	79	170
Sour gas plants	16	0	73	75	84	117
MSW	3	4	5	6	25	28
Refineries	11	0	70	60	82	102
Sweet gas plants	3	0	21	22	25	37
Education	1	0	10	8	28	31
Hospitals	1	0	6	6	17	24
Turboexpanders	5	6	12	18	13	21
Food industry	0	0	1	1	11	11
TOTALS:	103	15	824	953	1229	2165

All numbers are rounded to the nearest MW. The rounded total may differ slightly from the sum of rounded segment contributions.

Table C-3. Economic potential at lower capital cost - electric peak

Economic Potential (MW)	Size to Peak thermal					
Buyback Rate	3¢/kWh		5.25¢/kWh		7.5¢/kWh	
Segment	1992	2005	1992	2005	1992	2005
Petrochemicals	167	0	944	1573	1092	2725
Saw, panel board, CTMP	0	0	6	7	70	81
Kraft pulp mills	23	32	315	441	533	746
Oil sands mining	123	11	354	540	393	725
Gas flares	0	0	52	52	101	101
Oil sands in-situ	3	0	89	145	160	360
Sour gas plants	49	3	144	166	159	223
MSW	3	4	5	6	25	28
Refineries	45	0	143	140	161	206
Sweet gas plants	23	2	67	78	74	108
Education	2	0	18	15	57	63
Hospitals	3	0	26	22	86	119
Turboexpanders	5	6	12	18	13	21
Food industry	0	0	3	2	27	28
TOTALS:	446	59	2178	3207	2952	5533

All numbers are rounded to the nearest MW. The rounded total may differ slightly from the sum of rounded segment contributions.

Table C-4. Economic potential at lower capital cost - thermal peak

Economic Potential (MW)	Size to peak electric				Size to peak thermal			
Year	1992		2005		1992		2005	
Segment	Base	Low cap	Base	Low cap	Base	Low cap	Base	Low cap
Petrochemicals	6	25	0	0	55	167	0	0
Saw, panel board, CTMP	0	0	0	0	0	0	0	0
Kraft pulp mills	0	4	0	5	2	23	3	32
Oil sands mining	8	34	0	0	24	123	0	11
Gas flares	0	0	0	0	0	0	0	0
Oil sands in-situ	0	1	0	0	0	3	0	0
Sour gas plants	5	16	0	0	10	49	0	3
MSW	0	3	1	4	0	3	1	4
Refineries	4	11	0	0	10	45	0	0
Sweet gas plants	1	3	0	0	4	23	0	2
Education	0	1	0	0	1	2	0	0
Hospitals	0	1	0	0	0	3	0	0
Turboexpanders	3	5	1	6	3	5	1	6
Food industry	0	0	0	0	0	0	0	0
TOTALS:	28	103	2	15	109	446	4	59

All numbers are rounded to the nearest MW. The rounded total may differ slightly from the sum of rounded segment contributions.

Table C-5. Comparison of base case with lower capital cost scenario

Economic Potential (MW)	Size to Peak Electric					
Electric Rate	3¢/kWh		5.25¢/kWh		7.5¢/kWh	
Segment	1992	2005	1992	2005	1992	2005
Petrochemicals	6	0	208	170	365	753
Saw, panel board, CTMP	0	0	3	4	40	46
Kraft pulp mills	3	4	57	80	121	169
Oil sands mining	8	0	96	97	135	237
Gas flares	0	0	33	33	87	87
Oil sands in-situ	0	0	28	12	59	103
Sour gas plants	5	0	54	43	80	103
MSW	4	5	5	6	19	22
Refineries	4	0	53	36	77	87
Sweet gas plants	1	0	16	13	24	32
Education	0	0	7	2	28	31
Hospitals	0	0	4	2	16	24
Turboexpanders	3	1	10	14	13	20
Food industry	0	0	0	0	8	4
TOTALS:	34	9	575	511	1071	1719

All numbers are rounded to the nearest MW. The rounded total may differ slightly from the sum of rounded segment contributions.

Table C-6. Economic potential at base case and higher tipping fees - electric peak

Economic Potential (MW)	Size to Peak thermal					
Buyback Rate	3¢/kWh		5.25¢/kWh		7.5¢/kWh	
Segment	1992	2005	1992	2005	1992	2005
Petrochemicals	55	0	704	945	1036	2393
Saw, panel board, CTMP	0	0	3	4	40	46
Kraft pulp mills	11	15	207	290	430	602
Oil sands mining	24	0	274	348	374	670
Gas flares	0	0	33	33	87	87
Oil sands in-situ	0	0	57	30	122	232
Sour gas plants	10	0	111	107	152	206
MSW	4	5	5	6	19	22
Refineries	10	0	109	82	153	185
Sweet gas plants	4	0	52	49	70	100
Education	1	0	12	3	57	63
Hospitals	0	0	17	5	86	119
Turboexpanders	3	1	10	14	13	20
Food industry	0	0	1	0	18	17
TOTALS:	121	21	1596	1916	2655	4761

All numbers are rounded to the nearest MW. The rounded total may differ slightly from the sum of rounded segment contributions.

Table C-7. Economic potential at base case and higher tipping fees - thermal peak

Economic Potential (MW)	Size to peak electric				Size to peak thermal			
Year	1992		2005		1992		2005	
Segment	Base	Env'l	Base	Env'l	Base	Env'l	Base	Env'l
Petrochemicals	6	208	0	170	55	704	0	945
Saw, panel board, CTMP	0	3	0	4	0	3	0	4
Kraft pulp mills	0	57	0	80	2	207	3	290
Oil sands mining	8	96	0	97	24	274	0	348
Gas flares	0	33	0	33	0	33	0	33
Oil sands in-situ	0	28	0	12	0	57	0	30
Sour gas plants	5	54	0	43	10	111	0	107
MSW	0	5	1	6	0	5	1	6
Refineries	4	53	0	36	10	109	0	82
Sweet gas plants	1	16	0	13	4	52	0	49
Education	0	7	0	2	1	12	0	3
Hospitals	0	4	0	2	0	17	0	5
Turboexpanders	3	10	1	14	3	10	1	14
Food industry	0	0	0	0	0	1	0	0
TOTALS:	28	575	2	511	109	1596	4	1916

All numbers are rounded to the nearest MW. The rounded total may differ slightly from the sum of rounded segment contributions.

Table C-8. Comparison of economic potential - base case and environmental scenario

Economic Potential (MW)	Size to Peak electric					
Electric Rate	3¢/kWh		5.25¢/kWh		7.5¢/kWh	
Segment	1992	2005	1992	2005	1992	2005
Petrochemicals	42	0	344	601	413	984
Saw, panel board, CTMP	0	0	0	0	106	122
Kraft pulp mills	0	0	113	159	149	209
Oil sands mining	55	0	129	207	147	269
Gas flares	0	0	71	71	103	103
Oil sands in-situ	0	0	59	76	81	196
Sour gas plants	29	0	75	91	87	119
MSW	0	0	19	22	35	40
Refineries	25	0	73	76	84	103
Sweet gas plants	7	0	22	28	26	37
Education	1	0	15	12	28	31
Hospitals	1	0	9	10	17	24
Turboexpanders	8	9	12	19	14	21
Food industry	0	0	3	0	16	18
TOTALS:	168	9	945	1371	1307	2276

All numbers are rounded to the nearest MW. The rounded total may differ slightly from the sum of rounded segment contributions.

Table C-9. 1992 economic potential with alternate acceptance curve - electric peak

Economic Potential (MW)	Size to Peak thermal					
Buyback Rate	3¢/kWh		5.25¢/kWh		7.5¢/kWh	
Segment	1992	2005	1992	2005	1992	2005
Petrochemicals	348	0	975	2012	1129	2767
Saw, panel board, CTMP	0	0	0	0	106	122
Kraft pulp mills	0	0	412	576	539	755
Oil sands mining	184	0	358	602	407	743
Gas flares	0	0	71	71	103	103
Oil sands in-situ	0	0	122	207	163	401
Sour gas plants	73	0	145	185	165	229
MSW	0	0	19	22	35	40
Refineries	66	0	146	164	167	210
Sweet gas plants	33	0	67	88	77	111
Education	0	0	28	21	57	63
Hospitals	0	0	41	36	86	119
Turboexpanders	8	9	12	19	14	21
Food industry	0	0	10	0	38	45
TOTALS:	711	9	2407	4004	3085	5727

All numbers are rounded to the nearest MW. The rounded total may differ slightly from the sum of rounded segment contributions.

Table C-10. 1992 economic potential with alternate acceptance curve - thermal peak

Economic Potential (MW)	Size to peak electric				Size to peak thermal			
	1992		2005		1992		2005	
Segment	Base	5 Yr=50%	Base	5 Yr=50%	Base	5 Yr=50%	Base	5 Yr=50%
Petrochemicals	6	42	0	0	55	348	0	0
Saw, panel board, CTMP	0	0	0	0	0	0	0	0
Kraft pulp mills	0	0	0	0	2	0	3	0
Oil sands mining	8	55	0	0	24	184	0	0
Gas flares	0	0	0	0	0	0	0	0
Oil sands in-situ	0	0	0	0	0	0	0	0
Sour gas plants	5	29	0	0	10	73	0	0
MSW	0	0	1	0	0	0	1	0
Refineries	4	25	0	0	10	66	0	0
Sweet gas plants	1	7	0	0	4	33	0	0
Education	0	1	0	0	1	0	0	0
Hospitals	0	1	0	0	0	0	0	0
Turboexpanders	3	8	1	9	3	8	1	9
Food industry	0	0	0	0	0	0	0	0
TOTALS:	28	168	2	9	109	711	4	9

All numbers are rounded to the nearest MW. The rounded total may differ slightly from the sum of rounded segment contributions.

Table C-11. Comparison of economic potential - alternative payback acceptance curves

OTHER INDUSTRIAL ON-SITE PLANT CAPACITY AND GENERATION, 1990[1]

PLANT	FUEL	PLANT TYPE	CAPACITY MW	GENERATION[2] GW•h
Alberta Hospital Edmonton	Natural Gas Some Diesel	Steam Turbine	3.0	6.6
Alberta Hospital Ponoka	Natural Gas Some Diesel	Steam Turbine	1.9	2.7
Alberta Public Works	Natural Gas Some Diesel	Steam Turbine	2.0	3.5
Alberta Natural Gas Co.	Natural Gas	Internal Combustion	1.2	—
Alberta Sugar Co.	Natural Gas	Steam Turbine	6.3	11.5
Amoco Canada Petroleum Co. Ltd.	Natural Gas	Gas Turbine	1.8	6.8
BPCO Incorporated	Natural Gas	Steam Turbine	1.0	—
Canadian Salt Co. Ltd.	Natural Gas	Steam Turbine	1.6	6.5
Celanese Canada	Natural Gas	Steam Turbine Gas Turbine	19.8	75.2
City of Calgary - Glenmore Water Treatment Plant	Diesel	Internal Combustion	5.0	0.6
Daishowa Canada Co. Ltd.	Natural Gas Black Liquor	Steam Turbine	40.0	102.4
DOW Chemical	Natural Gas	Gas Turbine	180.0	—
Foothills Provincial General Hospital	Natural Gas	Steam Turbine	18.0	22.5
Gulf Canada Ltd.	Natural Gas	Steam Turbine	5.3	21.0
Home Oil	Natural Gas	Internal Combustion	1.4	6.6
Prairie Bible Institute	Natural Gas Diesel	Steam Turbine Reciprocating Engine	1.1	—

(CONTINUED)

PLANT	FUEL	PLANT TYPE	CAPACITY MW	GENERATION[2] GW•h
Proctor & Gamble Cellulose Ltd.	Natural Gas Black Liquor Wood Waste	Steam Turbine Internal Combustion	32.0	262.0
Saratoga Processing Company Ltd.	Natural Gas	Internal Combustion	1.4	—
Shell Canada	Natural Gas Diesel	Steam Turbine Internal Combustion Gas Turbine	27.7	9.4
Sheritt Gordon Limited	Natural Gas	Steam Turbine Gas Turbine	7.8	16.5
Suncor Inc.	Natural Gas Coke	Steam Turbine	64.0	358.8
Sunshine Village	Diesel	Internal Combustion	0.9	—
Syncrude Canada	Natural Gas	Steam Turbine Combustion Turbine	217.0 52.0	1 226.9
Transport Canada	Diesel	Internal Combustion	2.3	—
Canadian Turbo Inc.	Diesel	Internal Combustion	0.6	—
University of Alberta	Natural Gas	Gas Turbine	2.5	—
University of Lethbridge	Natural Gas	Internal Combustion	1.2	0.8
Weldwood of Canada Ltd.	Natural Gas Black Liquor Wood Waste	Steam Turbine	50.0	264.6
TOTAL			748.7	3 609.0

1 Only plants that report to the Board are recorded.

2 Generation from some plants may be negligible, unavailable or confidential.

Appendix E

Description of Cogenmaster

COGENMASTER

A Cogeneration Options Evaluation Model

COGENMASTER

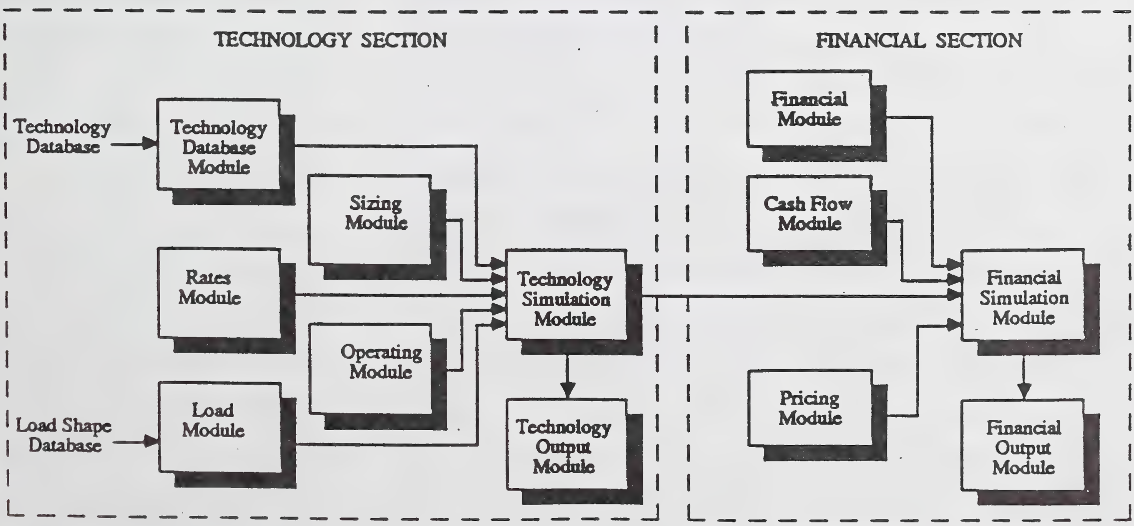
The changing economics of power generation, coupled with the legislative and regulatory initiatives that have followed the implementation of the Public Utility Regulatory Policies Act (PURPA) in 1978, have made cogeneration an attractive option for many industrial and commercial facilities. The wide range of financing and ownership arrangements now available to potential cogenerators – including joint ventures, partnerships, and third-party financing – has created the need for an analytical tool which can evaluate the financial impacts of these different arrangements on the participants in a cogeneration venture.

COGENMASTER is that tool. It is a micro-computer-based, menu-driven model that enables the user to examine the technical aspects of various types of cogeneration projects, evaluate their economic feasibility, and prepare detailed cash flow statements that spell out the costs and benefits to project participants. The model objectively evaluates and screens cogeneration options by comparing them to a base case scenario in which electricity is purchased from the utility and thermal energy is produced on-site. The options covered include different ownership arrangements as well as various technologies and operating strategies.

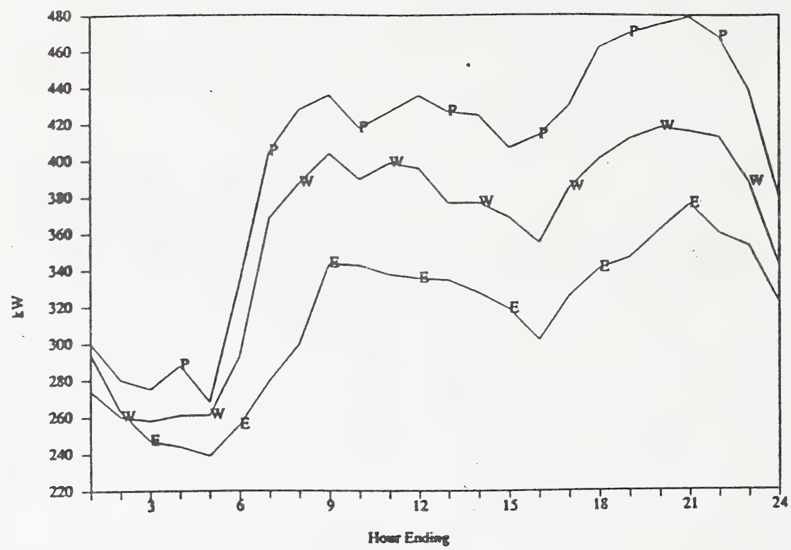
COGENMASTER CAPABILITIES

COGENMASTER can perform technical analyses of the different cogeneration systems that are feasible for a particular facility – from compact packaged units to large coal-fired steam turbines. Design-point and part-load performance data are used to carry out these analyses. The model can also compare alternative sizing criteria and operating modes. The system can be sized for base or peak, summer or winter, and electric or thermal loads; alternately, the user may specify the size of the system in kW. Three operating modes can be specified: electric load following, thermal load following, or constant operation.

COGENMASTER can take account of both scheduled and unscheduled maintenance outages when evaluating the economics of a cogeneration system. Most feasibility studies do not consider the costs of such outages, which can sometimes



Overview of COGENMASTER Analysis Structure



COGENMASTER can produce plots of building load profiles. Representative hourly load profiles for a hotel on a peak day (P), average weekday (W), and average weekend day (E) appear above.

double the payback period and render a project economically unattractive.

Due to changes in tax regulations and depreciation schedules over the last few years, a variety of ownership and financing arrangements have become available to those considering cogeneration. Any of a number of ownership combinations involving varying degrees of involvement by the utility, the facility owner, and third-party developers or financial backers can be analyzed by COGENMASTER.

COGENMASTER uses information about the ownership structure and the type of cogeneration system under consideration to simulate capital cost and operating cash flows over the project's useful economic life, and then apportions these estimates among the project participants. These cash flows are used to compute the net present value, internal rate of return, payback, and first-year debt-coverage ratio for each participant. These data enable the user to trace the impact of any type of cogeneration venture on the utility, the facility owner, and any relevant third parties for all practical combinations of ownership structure and operating mode.

COGENMASTER also factors in the effects of escalation rates on a project's economic viability. Feasibility studies of prospective cogeneration ventures are generally based on current prices for fuel and purchased power and the current inflation rate. COGENMASTER, on the other hand, computes the after-tax cash flow statement only after adjusting all relevant costs and revenues to take into account annual escalation rates over the economic life of the project.

COGENMASTER does *not* serve as a substitute for a detailed engineering feasibility study. However, such studies are expensive and time consuming, and become even more expensive in direct proportion to the number of options under consideration. COGENMASTER can perform a preliminary "what if" analysis very quickly, and identify those options that warrant a more comprehensive feasibility study.

An attractive feature of COGENMASTER is its portability. A customer service or marketing representative can perform a quick analysis of various cogeneration options right in a client's office; results of the model's simulations can be viewed instantly by the customer, eliminating the need for repeat visits by the customer service representative.

HOW COGENMASTER WORKS

COGENMASTER is completely menu-driven and is very user-friendly. It provides default values for all data requests. Graphical representations of load shapes can be summoned at the touch of a key. The model incorporates state-of-the-art programming tools, including context-sensitive help screens that are available at all times. The model was validated using data from existing and proposed cogeneration installations all over the U.S.

COGENMASTER consists of two major sections: the technology section and the financial section. The technology section includes five modules: technology database, rates, load, sizing, and operating. The financial section includes financing, cash flow, and pricing modules. In addition, each section has its own simulation and output modules. The modular approach

```
------------------------ COGENMASTER SUMMARY OUTPUT ------------------------
Title: NURSING HOME CASE STUDY                       Date: August 22, 1988

                                    115 kW Gas Engine
                 Sizing Criteria  :  User Sized
                    Power Output  :  115 kW per unit
                     Heat Output  :  0.646 mmBtu per unit
                      Fuel Input  :  1.407 mmBtu per unit
                 Number of Units  :  1

       Incremental cost, $ ($/kw)  :  99134 (862)
          Operating savings, $    :  39466
               Simple Payback     :  2.5 years
        Amount of financing, $    :  0
                  Term of loan    :  5 years
                 Interest rate    :  10.00 percent

                                     Utility     Facility    Third Party
        Net Present Value (000$)  :     0.         113.          0.
                  Rate of Return  :   .000        .356         .000
        After-tax payback, years  :   .000       2.909         .000
    First year debt coverage ratio :   .000        .000         .000
-----------------------------------------------------------------------------
```

Example of COGENMASTER summary output report

used in the design of COGENMASTER facilitates easy access to all data parameters and output reports. These reports can range in content from a brief one-screen summary report to a detailed seven-page monthly breakdown of energy and demand costs.

The model always compares the economics of the cogeneration system under consideration to the economics of the non-cogeneration, or base case, system. The cogeneration system consists of one or many units operating under a predefined set of conditions, such as hours of operation and dispatch mode. This system is then compared to a base case system in which the facility's electric needs are met by the utility and its thermal needs by on-site generation of steam or hot water using a boiler. Cogeneration and base case systems are juxtaposed in COGENMASTER's output reports, making comparison of the systems quick and convenient.

TECHNOLOGY SIMULATION

The first three modules in the technology section – the technology database, rates, and load modules – are used to prepare input files that will be read by the simulation program. The sizing, operating, and simulation modules are usually edited each time a simulation is performed.

The technology database contains design-point and part-load performance characteristics, installed cost figures, operating and maintenance cost parameters, and fuel characteristics for as many as 15 different cogeneration technologies. The specific attributes of the system under consideration must be specified by the user – as is the case with all five of the input modules in the technology section.

The rates module is very flexible; it is capable of handling both time-of-use and block rate structures. The user can specify up to four seasons and three types of periods: off-peak, partial-peak, and on-peak. Six periods per day – which can be different for weekdays and weekends, and for demand and energy charges – can be specified, and up to three blocks for demand and energy charges, and one buyback energy charge, can be input. Cogeneration costs are handled by a standby charge, a maintenance power charge, and a backup (supplemental) power charge. The cost of fuel – both the retail rate and the discounted cogeneration rate – and the cost of purchasing or self-generating steam must also be specified in this module.

Facility thermal and electric loads can be entered into the load module in one of three ways:

- a constant average load for every hour in the year
- three typical days of the year
- three typical days per month of the year.

Thermal loads may be in the form of hot water or steam.

The sizing and operating modules in the technology section permit a variety of alternatives and combinations to be considered. The system can be sized according to various types of load – base or peak, summer or winter, electric or thermal – or defined in terms of kW. Different modes of operation can be specified: electric following, thermal following, or constant operation.

FINANCIAL COMPUTATIONS

On the financial side COGENMASTER retains all the original strengths

of earlier cogeneration evaluation models developed by EPRI, while providing up-to-date information on tax and depreciation schedules, an internal capability to screen alternative cogeneration options, and an easy-to-use interface.

The financial, cash flow, and pricing modules in the financial section of COGENMASTER require information from the user relating to ownership structure, the installed cost for seven categories of equipment, and the contributions of project participants to both capital costs and the servicing of long-term debt, among others. Investment tax credits still available to projects that were already in development when these credits were eliminated by the Tax Reform Act of 1986 are taken into account, as are energy tax credits, which are also being phased out.

A load shape library accompanies the COGENMASTER software. This reference source contains electric and thermal (hot water) load shapes for nine different commercial building prototypes. The buildings are aggregated according to the weather zones represented by the cities listed below. Electric load shapes include cooling, ventilation, lighting, refrigeration, cooking, and miscellaneous end uses. Thermal load shapes include space heating and water heating.

Facility Types	Weather Zones
• large office	• Boston
• large retail	• Chicago
• hospital	• Fort Worth
• shopping strip	• Los Angeles
• school	• Miami
• non-refrigerated warehouse	• Raleigh
• fast-food restaurant	• Topeka
• full service restaurant	
• grocery store	

EQUIPMENT

The COGENMASTER Version 1.1 software comes on two 5-1/2 inch, 360K disks or one 3-1/2 inch, 720K disk. The program has been written for IBM PC/XT, PC/AT, and compatible computers which have a base memory of 512K, a 360K or a 720K floppy drive, and a hard disk, and which use DOS Version 2.11 or higher. Optional requirements are a graphics card to view and print load shape plots and a printer with which to produce output reports and graphs. COGENMASTER supports the Epson FX dot matrix printer and the Hewlett-Packard Laserjet printer, and the Color Graphics Adapter, Enhanced Graphics Adapter, and Hercules monochrome graphics display cards.

COGENMASTER Applications

- Cogeneration Feasibility Studies by Engineers
- Analysis of Rate Structures by Utility Rates Personnel
- Development of Cogeneration Technical Potential by Utility Planners
- Financial Analysis of Cogeneration Projects by Financial Planners
- Review of Cogeneration Loan Applications by Lending Organizations

COGENMASTER was developed for the Electric Power Research Institute by Synergic Resources Corporation

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